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ENERGY POLICY IMPLICATIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1989

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

SECOND SESSION

ON THE

ENERGY POLICY IMPLICATIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1989

JANUARY 24 AND 25, 1990

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ENERGY POLICY IMPLICATIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1989

WEDNESDAY, JANUARY 24, 1990

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 9:35 a.m. in room SD-106, Dirksen Senate Office Building, Hon. J. Bennett Johnston, chairman, presiding.

OPENING STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

The CHAIRMAN. The committee will come to order. What is the Energy Committee doing holding hearings on clean air?

Well, first of all, I was requested by 13 members of this committee to hold these hearings and, secondly, the issue of clean air impacts directly on energy use and on electric generation, not to mention economic growth, employment or unemployment and the economic health of the country.

The issue of clean air is probably the most important economic issue that this Congress will consider, maybe in this Congress and maybe in the whole decade. So, it is a matter of vital concern to all of us.

We are not trying to end run any other committee. I would guess while I have not talked to every member of this committee, I would expect that we have very strong support for clean air on this committee and support for if not the bill, then a very strong bill.

I am not at all sure that any member of this committee or that the committee as a whole will take any action to offer any amendment, either individually or collectively as a committee. Rather, we are here to examine the very difficult, the very important, the very complicated issues that have to do with this bill.

While there is strong support for clean air and while there is no intention, no predisposition that I know of, and I think I would know about it if it was to do anything particular in terms of an amendment, my guess is that there would be no hesitation to do it if these hearings would indicate that it was proper to do so, that some mechanism as proposed in either the President's bill or the environment and public works bill are not workable or are harmful either to the economy or indeed to the cause of clean air.

There are so many issues, both major issues and minor issues. Of course, some of the minor issues would be in any other context a major issue because they would have tremendous impact on maybe a region or an industry, but I think we have hearings that are calculated today and tomorrow to get to the heart of these issues. We only have 2 days scheduled. If necessary we can always call more hearings.

I do not know how long these proceedings are going to last on the Senate floor. In the caucus yesterday someone said 2 weeks. My guess is that 2 weeks will just get the show started. It is not going to conclude, my guess is, in 2 weeks, and we may want to have more hearings. That is not an announcement of additional hearings, far from it. It is just a recognition of the complication of this issue, the controversial nature of this issue, and the importance of the issue.

So, I look forward to hearing today from three panels of witnesses. The first panel will discuss the emissions cap, the allowance trading system, cost sharing, and issues pertaining to the acid rain provisions of S. 1630; that is, the EPW bill.

The second panel will discuss other energy policy implications of the acid rain provisions. The third panel will address the impacts of the air toxics and non-attainment provisions on the oil and gas and electric utility industries.

We plan to hear from the first two panels of witnesses today and return tomorrow to hear from the third panel.

Before I introduce the panels, I would like to turn to Senator Bumpers for an opening statement. I will submit an opening statement from Senator Murkowski.

[The prepared statement of Senator Murkowski follows:]

STATEMENT OF HON. FRANK H. MURKOWSKI, U.S. SENATOR FROM ALASKA

Mr. Chairman, I'd like to thank you for holding these hearings on the energy policy impact of the Clean Air legislation before Congress.

President Bush made a bold step in attempting to resolve the conflicts between environmental protection and economic growth in the bill he put before us in July. By changing from a "command and control" regulatory scheme to one that lays out the goals and allows American ingenuity to achieve them, we can take advantage of one of the most powerful sources of incentive in our country—the market.

I am greatly concerned with the cost of the Senate bill . . . more than twice that of the President's bill. We must be careful to properly assess what costs our industry must bear for incremental reductions in pollutants. At a time when Pacific and European countries are taking an increasing amount of our market share we must not demand that our industries funnel their assets into superfluous emission reduction expenditures.

So, we must be careful to pass legislation that keeps America healthy and working. Striking this balance is critical to the energy industry and I look forward to hearing from our witnesses today what effect these bills will have on their operations.

STATEMENT OF HON. DALE BUMPERS, U.S. SENATOR FROM ARKANSAS

Senator **BUMPERS**. Mr. Chairman, first of all, let me thank you for scheduling this hearing on one of the most important, perhaps the major piece of legislation that the Congress will consider this year.

I have two interests in the bill. The first one, of course, is the overall interest as an environmentalist and the recognition that we simply must clean up the environment.

My second one is much more parochial. There are some things in this bill that discriminate unbelievably against my state as well as a few other states. It is perplexing and, quite frankly, unfathomable how some of these provisions were written that could have such a perverse devastating effect on my state which has spent billions of dollars in the past in a visionary way to burn the cleanest coal possible and to do our part for the future in cleaning up the environment, particularly, and do what we could to reduce acid rain emissions.

For example, Mr. Chairman, there are a group of states that are in what they call the class of 1985, and we are limited to a large extent on our emissions in the future based upon your emissions in 1985.

Our emissions in 1985 just by pure circumstance and coincidence happened to be the lowest by far we have ever had or ever will have. We just happened to get super clean coal that year.

Secondly, our emissions—and, incidentally, the amount of additional emissions that we could take out by scrubbing is minimal and would cost over $700 million for the five units in my state. But, secondly, there is another group of states who, if they burned less than 150—if they had less than 150,000 tons of emissions in a certain year—and I guess that was between 1985 and 1987—and scrubbed their coal, they are exempt from the provisions of this bill.

By the same token, in my state we have only burned 60,000 though we do not scrub. In some instances we are well below, even though we do not scrub, those states that are allowed 150,000 tons and did scrub.

That is—what I am saying is generally I favor this bill, but as old Jerry Clower used to say when he was fighting that coon up in the top of the tree, shoot up here amongst us one of us has got to have some relief, and we have got to have some relief. Under this bill we have just borne the brunt of a tremendous burden of Grand Gulf and to impose this on top of that would be devastating to one of the poorest states in the nation.

I applaud the efforts that have gone into this bill. I strongly support it except for this provision and am most anxious to hear our witnesses explain some of these things, particularly how the allowance system is going to work.

I thought that was a really cockamamie idea the first time I heard about it. The more I studied it, the more I thought it had merit, and I have now come back to the point where I think it has some merit, but I am really curious about some facets of how that will work.

Thank you, Mr. Chairman.

The CHAIRMAN. Senator Burns.

STATEMENT OF HON. CONRAD BURNS, U.S. SENATOR FROM MONTANA

Senator BURNS. Thank you, Mr. Chairman, and welcome back and back to work, and I want to congratulate the Chairman for setting these hearings today because I think that finally this piece of legislation is being heard by a committee that deals with energy, and it is basically, I think, an energy bill.

These are indeed timely and important hearings. Environmental legislation has been put on a fast track by the president and by this Congress.

The Clean Air Act has not been changed or modified in more than a decade, and in that time our trucks and automobiles have gotten cleaner, markedly cleaner, but there are many more automobiles on the road today than there were a decade ago.

Combustion exhaust is no longer the major culprit. Now vapor admissions amount to a larger share of the pollutants and the dirty air in the major parts of our country. Stationary point sources of pollution are plants.

Our plants and our factories are also no longer the overwhelming causes of dirty air. They, too, have gotten cleaner on the average. Miscellaneous sources of air pollution now account for nearly one third of the total sources such as vapors that escape when you and I paint our house.

We strive for perfection in this country, as we must, but we know that we cannot in all reality achieve it with the demands that this society has. The need continues, however, to clean up the air in our larger cities. By implication, however, that needs to begin to impact our uses on energy.

Cars are driven by energy. Factories we work in are driven by energy. The homes we live in use energy. Our society is energy driven. To be otherwise would put us back into the dark ages.

The sources of our energy are diverse. We use oil, gas, hydroelectric power, nuclear power, solar, wind, natural gas and coal just to name a few. Each has its place in the overall energy mix. Each has its benefits and its problems. The benefits are obvious. The high standard of living that each American enjoys is in large part a measure of that benefit.

The problems are more difficult to get at, and they are more difficult to correct.

One difficulty has been our dependence on the dwindling stock of domestic oil and natural gas supplies. We need to spur the search for new domestic oil, sources of oil and natural gas through tax and other incentives. Those things that were taken away from this industry less than a decade ago.

These areas—there are areas of Montana that show great promise for new sources of oil and natural gas, but we also must recognize that the time will surely come when these sources, too, will become exhausted, even the oil that almost certainly lies under ANWR will buy us only a few more years of energy dependence.

We do not need just a Band-Aid approach. Already we are dependent on foreign sources for about half or over half of the oil we consume, and that total is expected to increase.

The reliability of our foreign source supplies of oil and gas is problematic at best. The economic engine that drives this country is too important to be held hostage to the whims of a few foreign potentates.

So, we need to consider alternatives we have of increasing our dependence on energy sources we have beyond ourshores.

Admiral Watkins and the Energy Department are to be commended for the initiatives in developing a national energy policy for this country for the next century. His efforts are timely, and they are appreciated, and it is time that this government gets ahead of the curve instead of the issue of reactive as it has been in the past.

A look at the Clean Air Act also brings many, many doubts to a lot of our minds, and I would ask, Mr. Chairman, that I have just a short statement here that I think is very important as we consider this act. Montana has enough clean coal to meet America's energy needs into the next century, coal from which methanol could be squeezed out and put to use, meeting a portion of our energy requirements in an environmentally sensitive way.

We also have plentiful supplies of agricultural stock to produce ethanol. If this is the road we are headed down, then we need to look at our own back yard for the resources we need to solve the problem.

I see no benefit to America in building up another huge foreign based energy infrastructure and I see every benefit to the United States of America in an environmentally sensitive way in our own domestic energy resources. We need American energy to meet American needs.

Imagine the potential we have in this country to deal with several of our major energy, environmental and economic problems through the use of biomass for the production of ethanol and the use of coal for the production of methanol.

This country has ample energy resources to meet its own needs entirely. We have a large agricultural base, and we have vast coal reserves. Montana alone has proven coal reserves with an energy value equal to that of Saudi Arabia's oil. Now, think about that whenever we start talking about clean air and our energy sources. Studies have shown that the United States by using methanol from coal could be energy independent, could substantially reduce the trade deficits, and could create hundreds and thousands of jobs for American workers and could vastly reduce the pollutants from automobile emissions at the same time.

It is not the end we seek. It is at least an option we should encourage into the future.

The CHAIRMAN. Gentlemen, I might note that we have a big list of witnesses today. I know the importance of this to all members, and I do not want to put a time limit on members, but if you will try to think about the witnesses we want to hear today.

With that, Senator Ford.

Senator FORD. Mr. Chairman, after you made that great speech I will forgo any kind of a statement and look forward to hearing from this distinguished panel.

The CHAIRMAN. Thank you very much.

Senator FORD. You are entirely welcome.

The CHAIRMAN. Senator Wallop.

STATEMENT OF HON. MALCOLM WALLOP, U.S. SENATOR FROM WYOMING

Senator WALLOP. Mr. Chairman, I wish I could be as obliging as the Senator from Kentucky, but opportunity is at hand.

Mr. Chairman, in the summer of 1988 anyone visiting Casper, Wyoming was assaulted with respiratory and vision impairments because of unhealthy air. Breathing the air in Casper was similar to what people here in Washington had experienced in the early 1970's, but there was a major difference. The dirty air of Washington was caused by ozone created by automobile traffic. The polluted air over Casper was a natural occurrence caused by forest fires in Yellowstone Park.

The example demonstrates that nature, not just humans, has its means for fouling the air. In all fairness, the Yellowstone fires were not entirely natural, in that the Park Service was following a let-burn policy with no action taken to fight the fires. In a sense the various toxic emissions resulted from human decision, if not human activity.

It is useful to ponder what would have been the results if the pending Clean Air Bill had been law when the fires occurred. The Yellowstone fires would have been in violation because the multiple sources of emissions had an adverse effect on public health and environment.

The bill creates a new concept of an attainment area. Entire regions will be blamed for any city which does not meet the attainment standards. Denver, hundreds of miles from Yellowstone, is a nonattainment area. Yellowstone's smoke could be blamed for Denver's inability to meet pollution standards, and even from time to time during that summer they added severely to that situation. Fires would have to be quenched, not an easy task, in order for Yellowstone to avoid sanctions by EPA.

The Park Service's fire management plan for Yellowstone would also violate the air toxic provisions of the bill by releasing toxics exceeding the 10- and 25-ton limits.

Now to some of you this example is fallaciour, but let me remind you that the OTA study on clean air pointed out that in many nonattainment cities, about 50 percent of the volatile organic compounds which cause ozone come from natural sources. If we want truly clean air, we will have to control not only utilities and industry but Mother Nature. Imaginative minds in Washington can find many other absurd effects in this legislation now being debated. These results are ridiculous in the sense that they are unnecessary, costly and ultimately of little benefit to the public.

For example, the bill seeks to force the use of a particular technology to control NOX emissions. Yet, this technology creates emissions which violate the air toxic provisions of the bill. So the facility would have to add a scrubber to the NOX cleaner.

Are we creating a situation where business will have to spend greater sums on clean air control equipment than it will on production facilities? It is clearly one way to remove America from the international marketplace.

Last summer in Jackson, President Bush began the debate on reauthorization of the Clean Air Act. He presented a workable proposal which included a number of innovative concepts such as the marketing of emission allowances.

Fortunately, the beast reported by the Environment Committee resembles a creature arising from the imagination of Mary Shelley, but, unlike Frankenstein, this work is redeemable. Many of the elements of the more sensible Bush program are still here, and in the months since the bill was printed the shortcomings of the legislation have been demonstrated.

Back in 1977 when I served on the Environment and Public Works Committee, a reauthorization bill was enacted. At the time, the environmentalists in the midwestern states utilities signed a pact with the devil. Robert Crandall from the Brookings Institute later documented this pact of regional protectionism. The high sulfur Appalachian coal markets were maintained. Utilities in the midwest were able to artificially keep down rates because their high polluting power plants were grandfathered, and environmentalists got their reauthorization bill.

The losers were the western and northeastern states. The western states lost markets for low sulfur coal and higher electric rates for their population because of the scrubber mandates for new power plants. The northeast received all the dirty emissions from the midwest.

The committee bill ostensibly corrects the mistakes of 1977, but on closer reading the flaws become evident. Under the acid rain title, the sulfur dioxide emissions cap will be required by the year 2000; however, the compliance deadlines based on last year's bill are unrealistic. Utilities will not be given time to use new clean coal technology or test low sulfur coal.

The only alternative will be to install once again more scrubbers. We seem to be unable to let loose our fascination with scrubbers while ignoring our requirements for clean air.

The air toxic title is another attempt to impose scrubbers on utilities and many other industries as well. This section is a disaster for many reasons. In this instance, coal-fired utilities would be required to control for air emissions with unknown, if any, health hazards.

The only technology for controlling the compounds released by combustion is through scrubbing. Thus, the air toxic provision mandates all coal-fired utilities to install scrubbers. If they do so for air toxic requirements, they may as well use them to meet their acid rain requirements.

The air toxic title is the most costly in the bill. It costs five times the annual cost of the acid rain section, $25 billion versus $5 billion. Yet, the rationale for the section is weak, if it exists at all.

Very few have been identified as carcinogens. Others are suspected of causing cancer, but the health research is totally incomplete, and for the remainder of the list no health effects are demonstrated, nor is there an attempt to demonstrate the health effects.

The President has suggested a 3-year study to identify culprits. This would make more sense than the committee bill approach. We are close to a decent bill, Mr.Chairman. There are other problems which everyone is frantically working on behind the scenes. Over the next few weeks we should be able to develop a bill which all the regions of the country can support which do in fact go to clean air and not regional economic considerations.

The CHAIRMAN. Thank you.

Senator Wirth.

STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

Senator WIRTH. Thank you very much, Mr. Chairman. As we can see by the comments this morning, this is going to be a long winter. I am pleased that the Senate has agreed to take the bill up, which it will be doing on the floor very soon. I think this is a very sound and good piece of legislation.

The emissions trading system that is in the bill advocated by Senators Simpson, Heinz and me I think is a very creative approach to the acid rain problems. I think the second round for auto emissions is very important. Without that, we end up being no further in the year 2003 than we are today. So that has to be retained, I think.

My own belief is that this toxic section which has been much discussed and will be further discussed is a good start on a very severe problem.

Finally, I think that the amendment on federal facilities and energy improvements creates a model that we ought to be pursuing and keeping in the legislation.

There are some holes in this, Mr. Chairman, and we will get to that on the floor, related to high altitude testing.

I think we also have the opportunity to do a good deal more work on the alternative fuels, particularly working with fleets.

I think the visibility issue related to the west is one that also has not been addressed yet in the legislation.

Finally, I think that there are some problems, as Senator Bumpers pointed out, with the so-called clean state provision, but we will have the opportunity to get to that as well as to the arguments which we are going to hear that somehow this is enormously onerous on one section of the country or another.

Senator Wallop was absolutely correct. We took it very tough in the west on the so-called old percentage reduction area, so we know what those regional unfairnesses are but we survived with that.

We will hear arguments that the automobile industry is not going to be competitive in the United States if this goes through. I do not really understand that argument. Maybe we will hear the reasons for that. I thought that every automobile, whether it was made in the United States or made overseas, would have to meet these stringent standards, and so why would the U.S. companies become less competitive and foreign companies more competitive with the same standards? That does not make a lot of sense to me, but maybe we can get some window on why that argument holds.

I hope that we get EPA to come out for the second round, Mr. Rosenberg. I am sure that you will see the light by the time the winter is over and we will get your support on that.

Mr. Chairman, thank you for holding this hearing. I think there is an enormous amount of merit in this bill, and let us move on. Thank you, sir.

The CHAIRMAN. Thank you, Senator Wirth.

Senator Domenici.

STATEMENT OF HON. PETE V. DOMENICI, U.S. SENATOR FROM NEW MEXICO

Senator Domenici. Mr. Chairman, I have to go to the Budget Committee, where we are having our first hearing. Could I inquire of you first of your intentions, just your best estimate? How long do you think we will be here with this first panel of witnesses?

The Chairman. I would hope until around 12:30, and then we will come back around 2 o'clock, give or take 30 or 40 minutes.

Senator Domenici. Mr. Chairman, I will have one of my staffers make sure that I am called before you finish them, even if I am the last person to inquire.

I have no long statement. I just want to say that it is time to have a clean air bill. We have been nine years waiting. However, I do not think that we ought to assume that the bill before the Senate is perfect.

I would just like to quickly say to those of you who want clean air, the ratepayers in the State of New Mexico for electricity pay about 33 percent above the national average. Part of that is because we are the cleanest, most scrubbed state in the union. In fact, where the new standard is 1.2 on SO_2, Mr. Chairman, we are on average .6 now.

One problem which I think maybe Senator Bumpers addressed is that we have no way of providing for future growth unless we buy from Ohio or Indiana or one of those states that currently are not very clean, and when they get to 1.2 they start to accumulate allowances. I think we have to find a way to be fairer to a state like New Mexico. There are a number of others. There are a number of southern states in the same position.

I have no magical answer, but I submit that we do not even get the benefit of any cleaner air out of this, which is really the frosting on the cake. We may not need a lot of growth energy, but it does seem to me that we have a fairness issue here.

Secondly, I am not sure but it seems to me that there are some economic considerations in this bill. Some would say economics do not matter. I think it matters. If, indeed, one provision in this bill on air toxics, if it ends up costing $14 billion a year about ten years from now and the President had a reasonable bill that costs $1 billion or even $3 or $4 billion, those are very big economic differences.

I say to my friend who is nodding, you know in the fiscal policy of the Nation look how long we worry about $12 billion worth of new taxes, and look how much we worry about putting $14 billion worth of taxes on American business. Well, if one provision, one portion, air toxic, goes from $1 billion in the administration's first bill, let me move it up to the year 2000 and say that the administration's cost was $4 billion and the provisions in this bill cost $14 billion.

Now I do not know as to the numbers, but I am told those are ranges. I think we ought to know what we really are getting for the $10 billion, and maybe we can find out. I think we ought to find out, and we ought to know what risks we are eliminating for $10 billion, and then we ought to ask what regulatory schemes are being imposed obviously to get there, because you cannot get there very easily.

Now obviously we need a Clean Air Act. We need one desperately. The act that we drew up basically in the Environment and Public Works Committee ten years ago is outmoded, and we must do something about it. I think we will.

I commend the Chairman and ranking member for calling this hearing. I think it is going to be effective, although I worry that it might be a little bit late. I merely want to say that I stand ready to work with Democrats and Republicans to get a good bill.

We must do something about acid rain. I might say to my friend from Colorado, I want to reduce acid rain by about the 10 million ton level, but I believe before all the discussion is finished that it is not going to be as easy to understand the rationale of the accumulated allowances and the transfer of them around the country as one might have thought at first.

It may be the way of the future, but it is very complex, very speculative. We really do not know how it is going to end up. We do not know what they are going to be worth, and we do not know who is going to have to pay. We do not know what new regional imbalances we are going to create because of that.

On the other hand, I think we can fix that one. I think we can make it more fair, and it will work. There are many other issues. Senators have addressed them. Automobiles and what we should do about mobile sources is a very difficult issue in this country, however, and we have to address it. I think we will, and we will do it in a realistic manner, and we will get much cleaner air for the American people when we are finished in the not-too-distant future on the floor of the Senate. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you. Senator Conrad.

STATEMENT OF HON. KENT CONRAD, U.S. SENATOR FROM NORTH DAKOTA

Senator CONRAD. Thank you, Mr. Chairman. I, too, want to commend you for holding these hearings and commend my colleague from Oklahoma for asking these hearings be held, because I think they are important. Mr. Chairman, I will dispense with my full statement in the interests of time, but a couple of quick comments.

First of all, clearly we need a Clean Air Act. I remember 20 years ago driving into Los Angeles, my eyes stinging, and for the first time hearing about a thermal inversion and being shocked to hear on the radio the news media advising the population to stay indoors, and if you had children to make certain that they did not exercise vigorously outside.

Mr. Chairman, I was just in Los Angeles again during this break, and I can say to you things have not improved very much and we have seen it in many days in Washington, DC, in the last 2 years. We heard the news media advising people not to exercise outside.

Something is wrong. It needs to be worked on, it needs to be fixed, and clearly, this bill is an attempt to do that, but I want to echo the comments of my colleague from New Mexico. There ought to be an economic test on some of these provisions. Rationality dictates that we do some cost-benefit analysis on legislation like this.

All of us want clean air, but it seems to me there ought to be some rational and reasonable economic tests that apply to these provisions.

I would be remiss if I did not mention the Clean States Provision. Mr. Chairman, I support that provision. That provision recognizes the tremendous investment that several states like my own have made already in emissions control.

North Dakota, for example, is one of only three states in the Nation, the others being Arkansas and Hawaii, that meet all of the Federal ambient air quality standards. North Dakota, by any test, has the cleanest air in the country, and we have that clean air because we have invested $350 million in scrubbing equipment to make it clean.

The Chairman has been there and he has seen it. The ranking member has been there and he has seen it. Our operational cost to run that equipment adds $23 million a year to our ratepayers' bills. As a group, the clean states have 85 percent of their generation coming from scrubbed units. The national average is 24 percent. So I believe the Clean States Provision has merit, and I want to make certain that everyone understands the clean states are still subject to the post-2000 cap on emissions and new units within these states must obtain allowances in order to operate after that date.

Mr. President, we are going to have a vigorous debate on that provision, as well as others, as we should.

One final point I want to make, and that is the international aspects of the Clean Air bill. In this country, we have spent literally billions of dollars—in fact, over $8 billion—on scrubbing equipment. Some of us compete directly with our friends to the north in Canada. Canada has over 20 coal-fired plants and not a single scrubber.

Now, our friends in Canada are quick to come and advise us we need to move on clean air, and that we need to move on acid deposition. I would say, Mr. Chairman, we ought to return the favor and remind our friends in Canada that they, too, have a responsibility and an obligation and as part of this legislation we ought to provide that if their energy is going to come into America it ought to be subjected to the same provisions and tests as the energy that we produce.

With that, again, Mr. Chairman I want to thank you for holding these hearings.

[The prepared statement of Senator Conrad follows:]

Statement of

SENATOR KENT CONRAD

Senate Committee on Energy and Natural Resources

Oversight Hearings on S. 1630, a Bill to Amend
the Clean Air Act

January 24-25, 1990

I thank the distinguished Chairman of the Energy Committee, Senator Johnston, for holding these hearings. Clean Air legislation will have a significant impact upon the nation's energy policy, and I think it is important that we examine those impacts before proceeding with debate on the floor.

I also commend my colleague from North Dakota, the Chairman of the Senate Committee on Environment and Public Works, Senator Burdick, and the members of that committee, for the work they have done to report this legislation. After years of debate, it is looking more and more like Congress and the President will finally agree on a bill to make the first major revisions in the Clean Air Act since 1977. I support that effort and look forward to enactment of a bill.

S. 1630, the bill reported by the Senate Environment Committee, is a comprehensive bill, and I will not comment here upon all of its major provisions. Rather, I will focus my remarks on certain aspects of Title IV of the bill dealing with acid rain because that title will likely have the largest impact upon energy policy. It will also have the greatest impact on the energy industry in my state.

One section of the acid rain title is the Credit for Clean States provision, and I support it. The provision recognizes the tremendous investment that several low density states, like North Dakota, have made in emissions control.

North Dakota, for example, is one of only three states - together with Arkansas and Hawaii - that meets all of the federal ambient air quality standards. We have invested $350 million in sulfur dioxide removal systems, and our operation and maintenance costs for those systems run $23 million per year. As a group, the Clean States have spent $3.2 billion on pollution control equipment, versus a total of $8.2 billion for the nation. As a group, 85 percent of the Clean States' coal-fired generation comes from scrubbed units, versus 24 percent for the nation.

The Clean States are still subject to the post-2000 "cap" on emissions and new units within these states must obtain allowances in order to operate after that date. The Clean States Credit, therefore, is simply an attempt to recognize the substantial investment that several states have already made to reduce SO2 emissions.

The bill also contains a "Sense of the Congress" resolution opposing fees or taxes as a method of sharing the costs of acid rain control. I support the committee's position on cost-sharing, and will oppose efforts on the floor that might force states that have already done their fair share to bear additional and disproportionate costs.

I was also pleased that the bill provides an extension for compliance for certain clean coal technologies. I am somewhat concerned, however, that the provision applies only to repowering technologies, and I am not certain that the extension is long enough to reap the benefits of the substantial investment that the nation has made in the clean coal technology program.

As comprehensive as the bill is, there is one major omission, and that is the failure to address the effects of international air pollution. Thus, there is, in effect, a major "hole" in the emissions "cap."

As the Environment Committee noted in its report on S. 1630, air pollution recognizes no state or international borders. The bill addresses emissions problems within the United States but it is silent on the subject of international pollution. If we are serious about our attempt to reduce acid rain, then we should broaden our efforts and include our friends to the north and south of our borders.

North Dakota, a state that borders two Canadian provinces, is very familiar with the problems of international transboundary emissions. As a producer of energy, we are also very sensitive to the impacts of U.S. legislation on international competition. Enactment of the Free Trade Agreement has crystallized the issue.

In North Dakota, for example, about 70 percent of our coal-fired capacity is fitted with scrubbers. In Canada, however, not a single coal-fired unit is fitted with a continuous emission control device. In Alberta and Saskatchewan alone, there are 5,954 megawatts of existing coal-fired capacity that are unscrubbed.

Projections portend more of the same for the future. While only 70 megawatts of coal-fired capacity is planned through 1998 for states covered by Clean States Credit, about 2,414 megawatts of coal-fired capacity is planned through 1998 for Alberta and Saskatchewan. Alberta alone plans 1,858 megawatts of coal-fired power for that period - 5 baseload units at between 360 and 386 megawatts each. No scrubbers are planned for any of those units.

Western Canada is not part of this acid rain reduction plan, yet these provinces sell power in the same power pools as U.S. utilities. If our international neighbors can export electricity to the U.S. in competition with American coal-fired generation, then they should be subject to the same or similar environmental standards. Free trade must mean fair trade, and I hope that the Administration will recognize these concerns as it implements the Free Trade Agreement.

Again, I thank the Chairman for holding these hearings and for forming the excellent panels of witnesses that are before us. I look forward to their testimony as we begin the floor debate on Clean Air.

The CHAIRMAN. Thank you, Senator Conrad. Senator Nickles.

STATEMENT OF HON. DON NICKLES, U.S. SENATOR FROM OKLAHOMA

Senator NICKLES. Mr. Chairman, thank you very much, and I also appreciate your holding these hearings. As evidenced by the attendance of senators and also by the length of the statements there are a lot of strongly-held convictions about this bill.

I think I have heard most everyone state that they support passage of a reasonable Clean Air bill, and certainly this senator does, and I would also like to support an affordable Clean Air bill. I am not sure that Senate Bill 1630 meets that test.

The President's bill, as I understand, was estimated to cost something like $18 to $20 billion. EPA estimates that 1630 would cost industry and consumers approximately $40 billion per year. The Business Roundtable, in a more comprehensive review of the bill, estimates annual costs to be somewhere between $80 and $104 billion per year.

On a per-household basis, that means that it would cost from $650 per household to possibly as much as $1,700 per household to comply with this bill, and that is increased utility bills, automobile costs, fuel cost, increased cost for thousands of consumer products.

I believe the level of cost can and should be reduced. A properly-crafted clean bill could achieve significantly similar reductions in air quality, or improvements in air quality and also achieve that at substantially less cost.

Senate Bill 1630, if it passes without major modifications, I believe the Senate and perhaps this Committee will be busy working on a rewrite within a few years.

Provisions of 1630 that have passed are almost certain candidates for radical revision under the "no-growth" caps inthe acid rain title. The technologically unfeasible standards set for mobile sources in both the second tier of tailpipe emission reductions and the CO_2 standards and the unjustified residual risk standards in the toxic air emissions title.

The Senate had to spend too much valuable time during the last few years undoing hasty or extreme legislation of prior congresses. We spent a lot of time repealing several sections of the Energy Security Act, the Synfuels Corporation, the Fuel Use Act, and more recently we were finally successful in finally decontrolling natural gas price controls and undoing some of the legislation that passed under NGPA in 1978.

I do not believe that by merely couching this bill as a major health bill, as the majority leader did yesterday, relieves the Senate of its duty to carefully and critically examine the bill, nor does health bill status make 1630 immune from the flaws that would, if left unchanged, require future congresses to come back and revise it.

Only last year, this Congress had to repeal two recent pieces of health legislation—Section 89 and the so-called Catastrophic Coverage Bill that just passed a year-and-a-half ago. Otherwise, we are going to be back here doing the same thing, repealing this legislation or significantly amending it.

Mr. Chairman, during floor consideration of 1630 I plan to offer, with Senator Levin, an amendment to strike the bill's provisions establishing carbon dioxide tailpipe limitations. These provisions are essentially a new corporate average fuel economy standard of 33 miles per gallon by 1996 and 40 miles per gallon by the year 2000.

They should not be considered in a Clean Air Act context. The result would be to price many automobiles out of price for most consumers. It would mean that we would be purchasing and mandating in many cases smaller automobiles, maybe less safe automobiles, and certainly increasing imports and costing thousands and thousands of jobs all across America.

I also intend to offer an amendment to substantially revise the permit program in Title V of 1630. This permit program would require permits on each and every emissions source from hundreds of sources in an oil refinery to perhaps a local gasoline station.

Each permit application would have to be approved by first the state air agency after notice and comment and then by the EPA, which is authorized to impose any new requirements on the applicant the EPA sees fit.

I look forward to the witnesses' comments on how on-shore oil and gas producers would be affected by the area source provisions in the law, coupled with the low emission thresholds of 10 tons per year provided in 1630.

I am concerned that stripper wells and field crude oil storage tanks might unnecessarily be drawn into the permit and control requirements of S. 1630.

The acid rain title of S. 1630 on which the Chairman has scheduled two panels contains an arbitrary sulfur emissions cap based on 1985 emission levels. Selection of this base period unfairly hurts "the clean states" like Oklahoma and New Mexico, Montana, South Dakota and others we have heard mentioned before, and is particularly unfair to Oklahoma because of the economic recession that hit our state and other oil patch states during the base period used to determine the so-called cap.

I look forward to testimony on recommended changes to the emissions cap approach used in this bill.

Mr. Chairman, again I thank you for having this hearing and I think this bill needs a lot of work, and this hearing will help us formulate some of the changes that need to be made.

Thank you.

The **CHAIRMAN**. Thank you very much. Senator Rockefeller.

STATEMENT OF HON. JOHN D. ROCKEFELLER IV, U.S. SENATOR FROM WEST VIRGINIA

Senator **ROCKEFELLER**. Thank you, Mr. Chairman. I think the reason that—I know that the Chairman is not pleased with the number of statements, but I think there is a reason for that, and that is that at least for some of us we have been meeting on this subject for about a year behind closed doors and this is really the first chance that any of us have had to say anything publicly about it, except those that are on the Environment and Public Works

Committee, and so I will be short but I have some things I want to say.

The CHAIRMAN. Well, do not be shorter than you have to be. [Laughter.]

Or longer. [Laughter]

Senator ROCKEFELLER. I think the point of this is that what we are talking about here is not just a Clean Air Bill, but we are talking about industrial policy, national employment, and the future direction of at least segments of our country.

I was a Governor for 8 years in West Virginia and I watched Ph content in our streams, and I am as strongly for the reduction of 10 million tons as anybody else. It has got to happen. It has got to happen in West Virginia, it has got to happen everywhere, so let us put that one aside. There has got to be that kind of reduction.

On the other hand—and I am also optimistic, incidentally. I think that there can be some good things that come out of this. As the Senator from North Dakota indicated, methanol is I think a very strong, important factor in our country's future. It is something the President supports.

There was a major bill that was passed on it a couple of years ago and it has real hope. Natural gas first, coal for the longer term—clean coal it will be—dramatic, important stuff for cleaning up the Nation's air, because so much of the filth comes out of tailpipes, not just out of smokestacks.

But I have got to tell you, Mr. Chairman, that I think this question of how we are going to allocate cost is not just frivolous. It is not frivolous at all, and it is not frivolous in any way to those of us who live in Appalachia and the Midwest. How are we going to do the environmental cleanup? How are we going to pay for it? Who is going to pay for it? I think those are legitimate questions and I think they are not well addressed in this bill.

The central industrial states are fashionable to attack. It is easy to attack states that have given other states the ability to grow. New Hampshire has the freedom to be very environmental because 51 percent of all the electricity that they get they get from coal miners in West Virginia.

They may or may not know what black lung is, they may or may not know about what it is to work in a coal mine, but before this debate is over—it is going to be a long debate and it is going to be a long year—they are going to have to know. They are going to have to know.

I mean, their 2.3 percent unemployment is something that we have never heard of in West Virginia, but there is a reason for it, and part of that is called coal miners and what they have done.

Now, without the central industrial part of our country I do not think our country has an industrial base. The Senator from Colorado was talking about percentage reduction and saying we have done so much more, we have paid all these bills. Well, of course they have paid lots of bills, because when their growth was taking place there was a higher Federal standard that was applying and they had no choice.

The west had to do that, because the growth which we would have loved to have had in West Virginia, which we would have loved to have had in the Midwest, but we do not, they did have, and the national standard was higher and so they have had to clean and scrub because that was what the law was. It was not any act of generosity.

We have been punished in central Appalachia by trade policy and by world markets, by our dependence upon coal, steel, glass, other things.

I was Governor for 8 years and 2 of those years unemployment was at 21 percent. I wonder what they know about that in New Hampshire now, or in Colorado, or a lot of other places in the West. What is 21 percent? That is the official figure. That means that the real figure is 25 percent, which means one out of every four people. That is depression. You do not talk about recession, you talk about depression.

So do not expect, Mr. Chairman, this member, who wants 10 million tons—you know, we have red spruce in West Virginia, too, and we do not want that gone. I do not want my Ph content cutting out the beauty. I know streams that I used to be able to dip my face into and drink water out of. You cannot do that now. I want that 10 million tons out. That is not what at debate here.

What is at debate is, how can we share the cost evenly? Padlocked plants—not many of those in Colorado. Maybe some now. Precious few in California, precious few in other places. Lots of them in West Virginia, more plants closed than any other state in the Nation on a proportional basis. I have got to deal with that, and I represent my people on this clean air issue.

Let me just say, and I will end on this, that we can indeed have a regional conflict course on this. We can go region against region and that will be a nasty fight, a long fight, and the Midwest and Appalachia and West Virginia may well lose.

We may well lose on that, because cost-sharing is now considered to be some kind of amoral or ridiculous concept. Oh, cost-sharing has gone. That is not a factor. You cannot do that.

I do not understand why. I do not know what is wrong with it—national problem. I think that West Virginia and Kentucky and Ohio and Indiana and Pennsylvania, and the Senator from Colorado referred to the Senator from Pennsylvania. I will guarantee you the Senator from Pennsylvania is not going to vote for this bill as it is.

So we can have a regional solution if we want and you can do 107 plants and put them all in the Midwest, and you can let the midwestern utilities, which have paid 50 percent or more of all the costs that have been spent on scrubbing in the history of this country, pay more. Pay, not twice, but three times. What was done, what they are doing and what they would have to do if this bill passed in the present form.

But regional conflict, Mr. Chairman, is not a wise course. I was delighted to help and vote for Charleston, South Caroiina when they had that, and for San Francisco when they had that. Everybody pummels money in. Those are called sudden tragedies. Congress responds.

There are some of those who would say that the history of certain parts of this country have been rather long-flowing tragedies, ebbing tragedies. The slow disintegration of economies, not because the people wanted it that way but because that is simply the way it worked out.

So that we can have regional conflict; I do not want it. But I will tell you one thing, it is not fair, and to make 107 units pay the cost for everybody else is wrong and this senator will oppose it and do what I have to, whether it be a winning or losing cause, to stand up for my people, who have made in West Virginia not an inconsiderable contribution to the success and the industrial prosperity of this country.

I thank the Chairman.

The CHAIRMAN. Senator McClure.

STATEMENT OF HON. JAMES A. McCLURE, U.S. SENATOR FROM IDAHO

Senator McCLURE. I would ask unanimous consent my statement by placed in the record.

[The prepared statement of Senator McClure follows:]

OPENING STATEMENT
SENATOR JAMES A. McCLURE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
WEDNESDAY, JANUARY 24, 1990 (9:30 A.M.)

CLEAN AIR ACT AMENDMENTS

I am glad to be here today to begin this year's Committee business with hearings on the Clean Air Act Amendments and their implications on our national energy, environmental, and economic policies.

I believe that environmental protection and economic growth can be compatible. Because the President's June 12th Clean Air Initiative was based on this principle, many members of the Congress applauded the President for his leadership in proposing a long overdue revision of the Clean Air Act. At the time, it was recognized that the Initiative would have profound economic impacts on our nation's energy future, but the attendant costs associated with the environmental benefits were considered justified. The President's proposal also had sufficient flexibility to enable regulated industries to adopt cost-effective pollution control technologies.

The Administration estimates the costs of their proposal at $19 billion annually. But the measure currently pending before the Senate, S. 1630, is a different story. The Administration informs us that not only is it accompanied by a price tag of $40 billion dollars annually, but what flexibility there was in the President's proposal has vanished on the winds of clean air. I might just note that the Business Roundtable's estimate of this cost is $54 billion annually.

Once again the Congress proposes to substitute its judgment for the scientific and technical expertise of EPA, DOE and other agencies in an attempt to make up for the perceived lack of environmental progress of the last Administration.

Under existing law, EPA already has the authority to take many of the actions mandated by S. 1630; for example, in the areas of toxic air pollutant controls and the regulation of fuel content. The President proposes to clarify existing law; but S. 1630 goes one step further and expands existing law dealing with toxic air pollutants, thus driving up the costs of implementation.

Recently the President enunciated five tests of balance and reasonableness that need to be preserved if we are to achieve a balance between the environmental progress and economic growth that the American people demand. Foremost among these is that the bill not impose aggregate costs on the economy that exceed the considerable costs already embodied in the Administration's bill.

Among the matters addressed in this legislation is the control of acid rain precursors. The acid rain provisions of the Administration's bill proposed rigid emission caps and a requirement that, after the year 2000, all new, grass root energy facilities must secure sufficient offsets to achieve zero emissions on a net basis. This requirement will have significant effects on both economic growth and the growth of electricity supplies regionally and nationally.

From the beginning of its consideration of Clean Air legislation in 1967 the Congress has followed the principle that "the polluter pay". With this legislation we are departing from that principle, and this departure will have significant implications for future economic growth in our Western states. Either that growth will not occur or it will occur under a Federally mandated allowance trading system that subjects the West to pollution licences derived from credits sold by mid-Western and Eastern polluters to defray their costs of control.

These are just a few of the concerns I have regarding this issue which I believe must be reviewed to better educate the Senate prior to its passage of any new clean air legislation. I hope we can fully explore these issues and I look forward to the testimony we will hear today and tomorrow.

Senator **Bumpers**. You can always pick out those guys who are not running for reelection, can you not? [Laughter.]

Senator **McClure**. Maybe as a matter of national policy it might help this country if nobody were. [Laughter.]

The **Chairman**. Well, finally, I think we are ready to hear from our panel.

Let me say to our witnesses I know you have excellent and lengthy statements. I would add to the great example that the Senators have set for you of brevity, I know you will be inspired to be brief. But we would like the opening statements to summarize, because we would like to get some give and take on some of these issues.

So, with that, let us begin with Linda Stuntz, who is Deputy Under Secretary of Policy, Planning and Analysis of the Department of Energy.

Ms. Stuntz.

STATEMENT OF LINDA G. STUNTZ, DEPUTY UNDER SECRETARY, POLICY, PLANNING AND ANALYSIS, DEPARTMENT OF ENERGY

Ms. **Stuntz**. Thank you, Mr. Chairman and members of the committee.

I appreciate the opportunity to appear before you today as you very appropriately consider the energy policy effects of this very complex and certainly controversial legislation.

We support the acid rain provisions of S.1630 to the extent that those provisions reflect the President's approach of harnessing the power of the marketplace.

However, the Department of Energy believes that the acid rain provisions of S. 1630 are deficient in four key respects.

First, the omission of critical clean coal technology regulatory incentives that were contained in the President's proposal.

Second, the advancement of deadlines by which these emission reductions must be achieved. Although one year may appear a minor matter to some, it, in fact, can be very significant, particularly for advanced abatement technologies which offer a real hope of cost-effective acid rain control.

Third, there is a significantly more burdensome nitrogen-oxide reduction requirement in the Senate bill than there is in the President's bill. That requirement, we believe, in fact may increase the cost of the acid rain control program by as much as a third.

Fourth, the costly and unnecessary targeting of federal facilities for unique energy conservation and fuel use burdens.

We will discuss on the next panel the clean coal technology incentives and the advancement of the deadlines, so I will not spend further time, in the interest of brevity, discussing those issues now.

Let me discuss briefly the things that you asked me to address on this panel, the allowance trading system, and cost-sharing, and the effect of the cap.

Both the Administration proposal and S. 1630 rely upon the allowance trading system to minimize and spread equitably the cost of acid rain control.

Without using the allowance trading system and moving strictly to a rate approach, for example, we believe it would cost 50 percent more in Phase I on a national basis, and 20 percent more in Phase II, to achieve the same level of environmental benefits.

The allowance trading system provides flexibility to the utility industry by permitting each company to implement the control strategy it thinks is most cost effective. Whether that is switching from high- to low-sulfur coal, or whether that is the installation of technology, the choice is left to the utility, because those decisions will vary greatly from region to region.

With the cap in place, creating a closed universe of allowances, utilities will be able to plan compliance strategies on a least-cost basis. We are aware that the allowance trading system has many critics. In my written testimony I have responded to each of the concerns that have been set forth.

I will be pleased to go into this further in the question and answer period; however; but let me move on now to cost sharing.

I heard and respect very much what the Senator from West Virginia has said. I think there is a feature of the allowance trading system and the Administration's approach that has not been fully appreciated. If you compare the allowance trading system to a strict rate approach, there is a real benefit. And yes, I would even say there is an element of imbedded cost sharing in the allowance trading system.

For example, when a dirty plant cleans up, under a strict rate approach, it does nothing but clean up. Under the President's bill, by cleaning up, it can generate assets, called allowances, that can be sold for money and that can be saved to allow for future growth.

Again, compared to a rate approach, the cleaning up of a dirty facility does not generate that type of asset.

Lastly, let me discuss this extremely burdensome addition to S. 1630, the targeting of federal facilities.

In addition to the potentially very difficult burden of implementing conservation requirements that may not even be possible to meet in certain facilities, such as our uranium enrichment facilities, S. 1630 would require all Federal facilities operating in affected unit service areas to obtain 10 percent of their electricity requirements from renewable or clean alternative fuels, which certainly sounds like a very laudable goal.

But if one looks closely at the provision, it seems to be sort of curious in that it declares certain fuels, natural gas and perhaps wood, as acceptable, while all other fuels, and especially coal, no matter how much you clean it up and no matter how clean it is when it comes out of the ground, would be unacceptable.

Even if it would be possible for every federal facility in a non-attainment area, such as your local post office, to figure out where it is getting its electricity from and whether or not it is getting 10 percent from the appropriate fuel, one of two things is going to happen.

Either you will simply shift the qualifying good fuels to that federal facility, leaving the non-qualifying bad fuels to other consumers, and so you will not really get any net environment benefit at all; or you will have to incur additional costs in order to meet this requirement.

Although we have not been able to cost out fully the effects of this provision, just for the Department of Energy's on our uranium enrichment facilities, which as this committee well knows are substantial consumers of electricity, we believe it could cost as much as $250 million per year. That is based on an assumption of moving to nuclear power, which would be the next most economical alternative available to us after the coal fired power we currently get.

And again, this would merely be a shifting of that nuclear power, probably from another consumer, to our federal facilities, and would not result in any net environment again.

With that, let me conclude and I look forward to your questions and let you get on with your hearing.

[The prepared statement of Ms. Stuntz follows:]

STATEMENT OF
LINDA G. STUNTZ
DEPUTY UNDER SECRETARY
POLICY, PLANNING AND ANALYSIS
U. S. DEPARTMENT OF ENERGY
before the
Committee on Energy and Natural Resources
UNITED STATES SENATE
JANUARY 24, 1990

STATEMENT OF
LINDA G. STUNTZ
DEPUTY UNDER SECRETARY
POLICY, PLANNING AND ANALYSIS
U.S. DEPARTMENT OF ENERGY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
JANUARY 24, 1990

Mr. Chairman and Members of the Committee. I appreciate the opportunity to appear before the Committee in support of the President's clean air initiatives. The Department of Energy supports the acid deposition provisions of S. 1630 to the extent those provisions reflect the President's approach of "harnessing the power of the marketplace." However, the Department of Energy believes that the acid deposition provisions of S. 1630 are deficient in four key respects: (1) the omission of critical clean coal technology incentives contained in the President's proposal, (2) the advancement of deadlines by which emission reductions must be achieved, (3) the changes in the nitrogen oxides provisions, and (4) the costly and unnecessary coverage of federal facilities. We also are concerned about the affects of the air toxics provision on utilities and we will discuss these concerns in separate testimony to this Committee.

Last July, the President sent to the Congress his clean air proposals. To reduce acid rain, the President proposed to reduce sulfur dioxide (SO_2) emissions by 10 million tons per year from 1980 levels. Nitrogen oxides (NO_x) emissions would be reduced by 2 million tons per year from 2000 projected levels. Emissions of these precursors to acid rain would be reduced by imposing an emissions cap on the electric utility industry permitting the industry to emit no more than 8.9 million tons of SO_2 per year.

The President's proposal and S. 1630 would achieve these emission reduction targets in the most efficient and least costly way. Each utility would have the flexibility to choose its least-cost compliance strategy. This flexibility is enhanced by an allowance trading program that enables utilities for which emissions reductions are more expensive to purchase emission "allowances" from those utilities that can reduce emissions more cheaply. This "harnessing the power of the marketplace" imposes the minimum burden necessary to protect our national and global environment while maintaining flexibility and fairness.

Alternatives to this market-based approach, such as governmentally imposed command and control policies, are much more costly to industry and to consumers. Estimates have indicated that command and control policies would increase compliance costs by 50 percent during Phase I of the program and by 20 percent during Phase II. At the same time, however, questions have been raised about the workability of this market approach in the electric utility industry. On balance, however, we believe that by providing the opportunity within the regulated electric power industry to use market-based emission control strategies, we can reduce substantially acid rain precursors with less cost and less disruption to regional economies than would occur under the alternative approaches relied upon in the past.

As you requested in your letter of invitation, I would like this morning to address energy policy considerations relating to the emissions cap, the emissions trading system, and cost sharing.

EMISSIONS CAP

The Administration proposed to cap utility emissions at 8.9 million tons of SO_2 per year. This cap on the level of emissions, assures the permanence of the 10 million ton-per-year reduction in SO_2 emissions. S. 1630 also relies upon a cap of 8.9 million tons of annual SO_2 emissions.

Without the emissions cap, reductions in SO_2 emissions achieved prior to the year 2000 could be offset by growth in utility emissions after the year 2000, thus negating a fundamental objective of the President's acid rain control program. In addition, the cap aids operation of the allowance trading system by creating a finite number of allowances. This helps utilities to value allowances and make compliance plans based upon the cost and demand for this finite number of allowances.

As a matter of energy policy, the emissions cap has two significant benefits: (1) it encourages use of new, low emitting, more efficient technology, and (2) it encourages cost-effective conservation. First, the Administration's proposal and S. 1630 encourage companies to take innovative steps to reach the targeted reductions and to generate tradeable allowance assets that can be sold or used for future growth. Under the emissions cap, the ability to use coal in electricity generation is directly related to the introduction of clean coal technologies such as integrated gasification combined cycle (IGCC) or pressurized fluidized bed (PFB).

With these technologies, growth can be accommodated along with acid rain reduction. This is why the clean coal technology incentives contained in the President's proposal are so important. As older, dirtier generation disappears through retirements and repowering, the use of new clean coal technologies will free up a sufficient number of allowances to meet the needs of future growth. For example, replacing a single 100 MW generating plant that controls only 70 percent of its SO_2 emissions would permit the construction of 30 plants of the same size if SO_2 emissions were controlled at a 99-percent efficiency factor due to use of more advanced technologies.

As the benefits and capabilities of new technology are understood, concern about the effect of the cap on growth is diminishing. For example, on January 4, 1990, the Public Utilities Commission of Ohio enacted a Resolution on Emissions Trading Within Federal Acid Rain Legislation. The full text of the resolution is attached to my testimony. The Commission expressed its view on the long-term effects of the cap as follows:

> WHEREAS, it is the view of the Commission that emissions permits will have a limited life of economic vitality as existing "dirty" plants are retired or retrofitted, as new technologies are implemented which will reduce emissions, as new plants meeting new source performance standards are brought on line, and as conservation and demand side management measures are implemented;

Second, as this resolution suggests, the emissions cap encourages cost-effective conservation. If a utility can reduce emissions over the 1985 base period by generating less, it will have allowances to sell. If a utility meets growth without actually having to generate more electricity (through demand-side management, for example) it will forego the expense of buying additional allowances to cover that growth or the expense of additional cleanup efforts. The result will be a cleaner environment and greater energy efficiency.

As we indicate in our response to your question on the likely impact upon natural gas markets, both the Administration's proposal and S. 1630 are likely to increase the demand for low-emissions generating technologies such as gas-fired combined cycle generation and the use of gas to cofire coal boilers. Consequently, an increase in natural gas consumption by the electric generation sector would be expected.

Natural gas use for electric generation has been expected to become increasingly competitive with respect to alternative fuels in many locations in baseload and intermediate load applications, even without the acid rain proposals. For example, the EIA Annual Energy Outlook (1990 Draft) base case projects that natural gas consumption by electric utilities will more than double from 1988 to 2000, from about 2.6 trillion cubic feet (tcf) to about 5.9 tcf. Any incremental consumption of natural gas as a result of acid rain legislation is likely to be relatively small, especially in terms of total natural gas consumption (18 tcf in 1988, 22.2 tcf projected in 2000). Recent DOE estimates of the natural gas resource base suggest that price effects of a modest increase in gas consumption also will be small, leading to insignificant changes in aggregate levels of natural gas imports.

Although DOE has not yet evaluated gas market impacts in detail, a DOE/EIA study entitled, Electricity Generation from Natural Gas: Prospects and Implications for the United States [SR/EPD/89-01, January 1989], determined that if coal costs were to increase by 10 percent, natural gas consumption would increase by approximately 10 percent in response. DOE expects the impact of both the Administration's proposal and S. 1630 to be similar. In both cases, DOE estimates that the effective increase in the cost of burning coal is approximately 8 percent, suggesting that natural gas consumption would increase by less than 10 percent (above the 2000 baseline). Coal use would decrease about 4 percent (roughly 30-40 million tons per year). Electrical generation by oil, nuclear, and hydro energy was unaffected by the increase in coal use costs.

Nitrogen Oxides Emission Reduction

The President's proposal and S. 1630 take different approaches to controlling nitrogen oxides (NO_x) emissions. The Department supports the President's approach.

The President proposed reducing NO_x using a baseline of 1989 emissions projected to the year 2000. S. 1630 proposes that NO_x reductions take place from a 1980 baseline. The S. 1630 baseline is much more onerous than the President's proposal. The 2-million-ton reduction from a 1980 baseline increases compliance costs by 33 percent and may not be attainable using existing technology in the required time frame. The President's proposal of reducing NO_x by 2 million tons from a 2000 baseline permits the companies to make the required reductions using technology that will be available at a reasonable cost (such as "low NO_x" burners) in the time frame proposed by the President.

In contrast to the control approach taken in the Administration bill, which requires use of low NO_x burner technology, S. 1630 requires use of either advanced NO_x technology, or additional SO_2 control technology to offset the NO_x emissions. These additional requirements are potentially very expensive. We believe that the emission rates set forth in section 407(b)(1) and (2) of S. 1630 are feasible for new units, commencing operation in 2000, but that they will be difficult to meet with low NO_x burners retrofit to existing units. Additionally, use of the 1985 baseline (a different baseline from the 1980 baseline cited above (see sections 401(b) and 402(o)) effectively makes these emission rates about 20 percent more stringent than they appear, given expected increases in capacity utilization between 1985 and 2000. Given that coal-fired utilities emitted about 6 million tons of NO_x in 1985, and assuming for the sake of argument that the rates in section 407(b)(1) and (2) are achievable at existing units, the use of the 1985 baseline with the stringent rates proposed implies that about 1.2 million tons per year (TPY) of NO_x control beyond that obtainable with low NO_x burners will be required. Based upon these preliminary estimates, our expectation is that this will lead to additional control of SO_2, which, with the 1.5:1 trading ratio between SO_2 and NO_x, means another 0.8 million TPY of required reductions in SO_2. We have not modeled the cost of controlling this extra tonnage, but rough calculations suggest that it could increase the cost of S. 1630 by about one-third, versus S. 1490.[1] If it proves impossible for existing units to meet the rates specified in section 407(b)(1) and (2) [even without the baseline adjustment], then the cost of these NO_x provisions could be even higher.

ALLOWANCE TRADING SYSTEM

1. Who Gets Allowances, When

Both the President's proposed legislation and S. 1630 would allocate emission allowances to a defined group of units. Each unit gets only enough allowances to permit it to emit at the statutory rate, based upon the unit's operating capacity over the 1985-1987 period. If the utility chooses to have a unit emit at a level above the statutory limit, or if the utility wants to increase the unit's capacity, thereby generating more emissions, then it will have to buy allowances. If the utility chooses to control emissions below the statutory level, then it will have allowances to sell or use for greater capacity utilization. Each company can decide upon its own implementation strategy, balancing the costs of buying allowances versus the costs of controlling emissions.

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[1] A good rule of thumb for costs is that they double for every 2 million tpy of SO_2 reduction over 8 million tpy. For 0.8 million tpy, costs would increase by 33 percent.

The implementation of the emission control program is spread over two phases. The President's Phase I starts after December 31, 1995, while S. 1630 starts after January 1, 1995, a full year earlier. We are sympathetic with the need to clean up our environment as quickly as possible; however, reasonable lead times must be available to implement an emission control strategy if costs are to be minimized and flexibility increased. That is why the President chose December 31, 1995, as the starting date. Because a number of months have elapsed since the introduction of the President's proposal, it is all the more important that the President's proposed emission reduction schedule be maintained, including the date of the very tight Phase II emission standard. The President's Phase II starts after December 31, 2000, while in S. 1630 it starts essentially one year earlier, January 1, 2000. Again, we prefer the President's Phase II starting date.

While it is inappropriate to shorten lead time excessively, the President's proposal encourages the acceleration of environmental benefits by allowing utilities to bank unused Phase I emissions allowances for sale or use in Phase II. Banking is a perfect example of how environmental and economic interests can be harmonized. Utilities that can make emissions reductions beyond their Phase I requirement at a cost below the expected value of allowances in Phase II market would accelerate environmental progress and lower their own compliance costs by taking advantage of the opportunity to bank. Banking is a likelihood, not a theoretical possibility. The ICF model runs performed for EPA, which do not incorporate banking, show a significantly higher allowance value in Phase II than in

Phase I. This outcome suggests that utilities will have a strong economic incentive to accelerate environmental progress by not using all of the available allowances during Phase I.

Under the President's proposal, Phase I would cover 107 named units, and any others as large as 100 megawatts (MW) and emitting 2.5 or more pounds per million BTU (lbs/mmBTU). S. 1630 covers the same 107 units but eliminates the other potential units from its coverage. During Phase I in the President's plan, the covered units can trade allowances within a state or within a single company if the company's operations cross state boundaries. In S. 1630, the trading area is two large regions (37 states east and 11 states west of the Mississippi River). The Department supports this portion of S. 1630 insofar as the larger trading regions would make it easier to find and trade allowances. During Phase II the President's plan would extend to these two large regions. In both plans new units would not be required to obtain allowances until Phase II. New units could obtain allowances from throughout the lower 48 states, rather than being limited to the smaller geographic areas.

In Phase II of the President's plan, the units covered expand to all units of 75 MW or greater emitting 1.2 or more lbs/mmBTU. Estimates indicate that this would cover about 600 units. Units that are less than 75 MW or emitting less than 1.2 lbs/mmBTU would not be issued allowances; however, they would be limited to their 1985 emission rate. This means they could increase their capacity or fuel consumption as long as they maintained their 1985 emission rate. Thus, some electricity growth could be met by relying upon greater utilization of these smaller and cleaner units.

These smaller and cleaner units could join the allowance trading system voluntarily. If they joined they would be given allowances and would be full-fledged participants in the allowance trading system. When the smaller and cleaner units retire, the Department believes that the owners of these units should retain their allowances, if they have opted into the program, or be granted allowances if the original units had not become a part of the program (provided that total allowances remain within the 8.9 million ton cap). Moreover, industrial and process steam units could join the allowance trading system as well.

S. 1630's coverage of affected units in Phase II is much more complicated. It starts off the same as the President's plan covering units greater than 75 MW emitting 1.2 or more lbs/mmBTU. It also freezes the emission rate for oil and coal units less than 75 MW that emit more than 1.2 lbs/mmBTU. But for units emitting less than 1.2 lbs/mmBTU, S. 1630 differentiates based upon fuel usage and historic emission rates. The effect also is to provide some equity to those units that already cleaned up their emissions.

S. 1630 introduces an inflation factor of 20 percent for these lower emitting units. The formula for determining their allowance allocation adds 20 percent over their lifetime to their baseline providing them with flexibility to respond to increasing demand. This inflation factor is provided as a quid pro quo for past clean-up efforts, at least for those units that did clean up.

The finite number of allowances that would be distributed, about 8.9 million in S. 1630, imparts a value to each allowance. The value of an allowance would be based upon the marginal cost of controlling emissions.

2. How the Allowance Trading System Works

How would a company go about planning for emissions control in an allowance trading system?

To begin, each utility would estimate the electricity demand it must meet and then plan how it will satisfy that demand, including the utilization of its existing units and the construction and utilization of new units. Based upon the price of various production inputs, including fuel, capital, labor, and emissions allowances, a utility would decide the least-cost strategy to serve its customers. Utilities would decide whether it is cheaper to: (1) control emissions through scrubbing or fuel switching, (2) over-control and sell surplus allowances, (3) build new, low-emitting capacity, (4) encourage conservation and energy efficiency, (5) buy allowances, or (6) use some mix of the above listed strategies or any others that are cost effective.

As an example, let's say that there are two companies and each has one generating unit. Each has been allocated allowances based upon a 1.2 lbs/mmBTU standard and each currently is emitting above that standard. Furthermore, let's assume that the cost for lowering emissions is $500 per ton for Company A and $1000 per ton for Company B. If allowances are selling for $700 per ton, then Company B knows that for its unit it is cheaper to buy allowances than to spend $1000 per ton to control its emissions. For Company A it would be cheaper to spend $500 to control emissions. Company A also knows that it could go below the 1.2 lbs/mmBTU standard and still spend only $500 per ton for its emission control costs. Therefore, Company A could overcontrol and sell its surplus allowances to Company B for $700 per ton, making $200 per ton for each allowance it sells. Company B could buy allowances at $700 per ton which would be a cheaper alternative than investing in pollution control costs costing $1000 per ton. Overall, emissions would be lowered by the required amount since the average of the two companies would equal the reductions if each company controlled to the 1.2 lbs/mmBTU requirement. Moreover, pollution control costs would be minimized in this allowance trading system rather than having each company pay its own marginal control costs.

3. Would Allowance Trading Work as Intended?

There are very strong economic incentives for companies to participate in the allowance trading system, since gains from allowance trading will increase revenues and profits or lower costs. However, there have been many suggestions that companies would not participate and that the allowance trading system would not work as intended. The suggested problems include anticompetitive behavior, market barriers, incentives to withhold allowances, inability to profit from sales, possibility of not recovering expenditures needed to generate allowances, and regulatory-induced hoarding.

a. Possibility of Anticompetitive Behavior

From a structural perspective, anticompetitive behavior will be difficult because the emissions allowance market will not be very concentrated. Market power develops when a market is so concentrated that a few companies will be able to dominate the market. Our analysis shows that the market for emission allowances will be relatively unconcentrated. About 600 units will be given allowances in the initial part of Phase II. Combining the units into at least 39 companies, the top four companies will have about 32 percent of the allowances, the top eight will have about 45 percent, while the top twenty will have about 73 percent of the market. These numbers indicate that the market will not be highly concentrated and the development of market power on the part of any one or more companies is highly unlikely.

Using the Herfindahl-Hirschman Index (HHI), used by the Department of Justice in its merger analysis to determine concentration levels, we have calculated an HHI of about 426 for the emission allowance market. This is substantially below the 1000 level that is the upper range for an unconcentrated market according to Justice's 1984 Merger Guidelines.

In contrast, those industries that supply the electric utility industry are much more concentrated. For example, the HHI for turbines and turbine generator sets is 2855 and the HHI for power and distribution transformers is 1490.

While it is possible that utility companies could behave collusively to suppress competition, the threat of prosecution under the antitrust laws, with the potential liability of treble damages, should be sufficient to stop any concerted actions on the part of participants.

Individual company behavior to keep competitors out of the market or to exert some form of market power also is not very likely. The trading markets are quite broad geographically, and no one company would have enough of the market share to be able to exert any undue influence over the market or entry into the market. New entrants into the market would be able to seek allowances from anyone in the nation, so that any company trying to influence the market would have to be able to exert nationwide influence. No individual company would have this type of market power. Moreover, new entrants would have a variety of fuel and technology choices that could be used that require few or no allowances. New companies, therefore, could undermine attempts to keep them from entering power generation markets. Consequently, we see no anticompetitive or market barriers to prevent the development of a well-functioning emission allowance market.

Some have argued that companies would not participate in the allowance trading market because they will retain allowances to meet future growth requirements. Allowance holders and potential users, however, can be expected to develop creative contractual relationships that will help promote a well-functioning allowance market.

Consider a situation in Phase II (since that is where many of the problems are alleged to occur) where a company has adequate generation capacity for five years and then will need to add to its generation mix. One option would be for the company to bank its allowances until it needed them in the future. This strategy would be economically wasteful since the company would be foregoing the opportunity to sell its allowances now and buy them back in the future, a strategy with a positive net present value. A creative way to avoid any hesitancy about selling allowances now is to lease the allowances for a set period and then recover them when they are needed. In this way, the company would have them available when they are needed in the future and increase revenues in the meantime.

Another way to assure that allowances are available is the use of direct contracts. Let's return to the example I used before with Companies A and B and their two units. Company B needs allowances; otherwise, it will have to spend $1000 per ton of SO_2 to meet the statutory limits. Rather than going to a middleman or broker to acquire allowances, it could go directly to Company A and negotiate a deal whereby Company B, in essence, pays for Company A's emission controls, at $500 per ton, so that Company B can acquire the number of allowances it needs to avoid its $1000 per ton investment. This form of direct action is reminiscent of past EPA emission trading programs in nonattainment areas where companies bought emission offsets from existing sources in order for companies to enter or expand operations in highly polluted areas. Direct action is a very likely consequence of the allowance trading system in addition to active trading by brokers. It is another way to overcome the hesitancy of companies to participate in the allowance trading system.

b. Effect of Regulation upon Trading Allowances

The argument has been made that the electric power industry is different from other industries because it is highly regulated at the federal and state levels. Because of this regulation, it is argued, companies will not willingly participate in the allowance trading system because of obligations to serve, prudence reviews, flow through of gains from allowance sales to ratepayers, and the inherent conservatism of the industry. While we are aware of all these regulatory-related issues, we do not believe that regulation will prevent the development and operation of a workably competitive allowance trading system. As we discuss in the next section, some participants may choose to sit on the sidelines and not participate in the allowance trading system. But not every company has to participate to assure the success of the allowance trading system.

Regulation-Induced Hoarding

The most often voiced argument is that state regulators will prevent active trading of allowances since the regulators will want companies to hold onto allowances to assure future growth and to preserve a reserve margin of allowances. As the recently passed Ohio PUC Resolution illustrates, however, it is unlikely that all state regulatory agencies will want companies under their jurisdiction to hoard allowances.

The Ohio PUC stated:

> RESOLVED, that it shall not be the policy of the Commission to encourage utilities to hoard the permits earned, but rather to best utilize them to reduce the overall costs of complying with clean air requirements and to assure that Ohioans maximize the economic benefits from permits during the limited time window in which the permits will be tradable and of economic benefit.

This only makes sense. Allowances are assets. To "hoard" them deprives the company and its ratepayers of revenues and runs the risk that the value of allowances will decline over time as old, dirty facilities are retired.

Let's assume, however, that some state regulatory agencies want companies within their jurisdiction to hold their allowances. This could be rational regulatory behavior, if expectations are for increasing allowance prices. If enough companies hold for higher prices, supply will fall and allowance prices will rise until enough holders sell to stabilize or reduce prices. This is a risky game, however, because allowance prices in fact may not rise due to decreasing demand on account of new technology, fuel switching, and conservation.

Another motivation for directing companies to hold allowances could be that the state agency envisions the need for allowances to meet future growth. But meeting this need by hoarding is not in the ratepayers' interests because it would not minimize rates. A better way to serve both short-term ratepayer interests and longer-term growth needs would be to lease the allowances while they are not needed, but structure the term of the lease so that the allowances would be available for the leasing company when growth needs arise. Indeed, if the Ohio PUC is correct about the declining value of allowances over time, and we believe they are, it would be better to clean up as early as possible, sell allowances for premium prices, and buy any needed allowances later at lower prices.

Another incentive for some states to encourage allowance trading is their desire to protect local coal interests, whether they are producers or consumers. If high sulfur coal is mined in the state or used in the state, the state will want to find ways to ensure that this coal can continue to be used well into the future. Coal-fired units will have the largest demands for allowances and high sulfur coal users will have the greatest demands among the coal-fired users, until new technology can be applied. If internally generated allowances are insufficient to meet these needs, then an active allowance trading system will be crucial to the needs of high sulfur coal producers and coal users. A thin allowance trading market could drive up the price of allowances to the detriment of high sulfur coal users. This would encourage fuel switching (to low sulfur coal or natural gas) to the detriment of many high sulfur coal producers. Therefore, the best interests of coal producing and coal using states will be to make sure that an active allowance trading system exists.

Another argument advanced is that regulated companies will not want to participate because all the gains from the sales of allowances will redound to the benefit of ratepayers and not to shareholders. But this assumes that states will not want to encourage their utilities to be good traders, an assumption whose universal validity we reject. Presently, most companies find that there are sufficient regulatory cost minimization incentives to participate in bulk power economy interchange agreements and spot purchases, as well as to participate in regional power pools. The reason that they do participate in these programs is that they permit utilities to benefit from least cost strategies. State agencies encourage this form of participation in order to keep costs to a minimum and to permit the savings from these programs to be flowed through to ratepayers in the form of lower rates. Even if all benefits of trading go to lower the utility's rates, this helps the utility remain competitive with other fuels, an important consideration to any utility manager.

A further argument that the allowance trading system may break down is that utilities will be reluctant to invest in projects to control or overcontrol acid rain precursors because a state agency may disallow all or part of the investment as imprudent. This argument presumes that the potential seller of allowances must foot the bill for overcontrol prior to making any sales. In fact, while it is impossible to know exactly how markets will develop, the extent of concern expressed regarding the availability of allowances for growth suggests that buyers of allowances could well be eager to underwrite the costs of overcontrol as part of an arrangement to secure a supply of necessary allowances. In any event, we think it is wrong to assume that all state agencies will act irrationally. As we already have stated, and as the State of Ohio already has recognized, it can be in the state's and the utility's best interests to "in effect, overcomply, with the law."

Other states, such as Indiana, already have passed legislation designed to reduce the risk to utilities in demonstrating new technologies. [Indiana recently passed P.L. 105-1989, which became effective on July 1, 1989, and provides that utilities engaged in clean coal technology demonstration projects have the ability to obtain preapproval of the prudence of expenditures for such projects. They also can qualify for accelerated depreciation, construction work in progress, recovery of preconstruction costs, and property tax deductions. Florida and Ohio also have adopted clean coal technology incentives.] The Administration's proposal contains a provision encouraging other states to adopt similar measures. This provision was deleted from S. 1630 [See section 515(e) of S. 1490] as were other provisions important to the earliest and broadest possible use of new technologies [See sections 508(c) and 515(c)-(d) of S. 1490]. With these provisions and the inducement provided by the trading system, we believe new technologies will be used in a manner that helps us meet both environmental and economic objectives.

Regulatory Inducements to Participate

Both the Federal Energy Regulatory Commission (FERC) and state agencies can take steps to assure that companies within their jurisdictions participate in the allowance trading system. FERC or state agencies can use their power to determine just and reasonable rates and their power over prudence reviews to make sure that jurisdictional companies do not hoard allowances to the detriment of ratepayers. Foregone revenues from allowance hoarding could be imputed against a company's revenue requirement, effectively penalizing a company for not participating in the allowance trading system. FERC or the state agencies could place conditions on their orders indicating that other necessary regulatory authority will not be forthcoming unless the company participates in the allowance trading system. All of these regulatory actions could be taken to induce companies to participate in the allowance trading system.

Allowance Reserve

S. 1630 contains a provision not found in the President's plan, an allowance reserve. In S. 1630, the EPA would withhold two percent of the allowances distributed in each Phase. These allowances would be available only to new entrants who showed that allowances were not otherwise available. The allowances would be sold at $1500 per ton. The monies collected from any sales, or any remaining allowances, would be remitted back to the units from which they were obtained on a pro rata basis at the end of each Phase. While a viable allowance trading market should emerge even without the reserve, the allowance reserve may be desirable to assuage the concerns of some potential allowance purchasers, especially independent power producers (IPPs). With this provision, IPPs can obtain financing, knowing that allowances will be available and that they will not have to pay more than $1500 per ton.

The Department views the allowance reserve system as an appropriate one, although other "seller of last resort" approaches are possible.

Consideration also should be given to when the monies and allowances should be redistributed. The bill now provides a redistribution at the end of each Phase. Phase I has a termination date but Phase II does not. Thus, at the end of Phase I, monies and allowances could be redistributed; however, in Phase II the monies and allowances would remain with the EPA indefinitely. We would recommend that the monies and unused allowances be redistributed more frequently than every five years, if the EPA determines that to be appropriate.

COST SHARING

The last issue the Committee asked that we address on this panel is cost sharing. Many have argued that an unfair burden is being placed upon companies in the Midwest due to the high costs imposed to meet the new emission control standards. Others have argued that it is unfair for those companies who already have cleaned up to contribute towards the cleanup of other, dirtier units. Let's put some perspective on these arguments.

A company must account for each cost factor in determining its cost of production. We all know about labor, capital, energy, and a host of other variable costs that make up the costs of production. These are internalized costs because they are internal to each company. The company must cover these costs if it wants to stay in business. There are some costs, however, that are not necessarily internal to the company. Pollution is one of these costs. If a polluter can use the air, water, or land without any cost, then the polluter is benefitting while others pay for this pollution. The existence of external costs is one reason why government intervenes in the marketplace, to help internalize the cost of the pollution. If external pollution costs are not internalized in the cost of production, the price of the end product will be too low. Consumers wind up demanding too much of the product because it is priced lower than its full cost of production. And those in a position to control pollution have no incentive to do so because they are not rewarded for such controls by the marketplace.

In the electric power industry, the Clean Air Act has gone a long way towards making sure that pollution costs are internalized and that the price of electricity reflects the costs associated with controlling pollution. But the Clean Air Acts of 1970 and 1977 have not solved this problem completely. Because of the various requirements for different powerplants depending upon age and other factors, a disproportionate share of pollution costs have not been internalized. In some areas of the country, primarily the Midwest, a high proportion of pollution costs are still external to the system. Other areas of the country have been required to apply more rigorous pollution controls, the costs of which are being paid for by consumers in these areas. Viewed in this perspective, then, we can say that some polluters have benefitted financially from the-lack of implementing emission reduction strategies while other polluters have been paying for their cleanup efforts.

The Administration has proceeded on the basis that the companies that are most responsible for pollution should pay for the cleanup, but it recognizes the need to minimize the cost of cleanup for everyone. Consider the effect upon the Midwest if there were no emissions trading system and no cap. The only way to achieve a ten-million-ton reduction in SO_2 and a two-million-ton reduction in NO_x would be to impose upon all power plants a very low rate of emissions. Regardless of the costs of emissions reductions, all plants would be required to clean up to the same level. Under such an approach, the Midwest would be hit even harder because it has nothing to sell, as it does under the President's allowance trading proposal. Estimates indicate that the costs of this kind of cleanup requirement would be 50 percent higher in Phase I and 20 percent higher in Phase II.

In 1980, the States of Ohio, Indiana, Pennsylvania, West Virginia, Georgia, Missouri, Illinois, Tennessee, Kentucky, and Alabama accounted for 51 percent of total SO_2 emissions but they accounted for 65 percent of utility SO_2 emissions. By 2000 (the start of Phase II), the ten states will be responsible for about 79 percent of utility emissions reductions; however, they will be paying only 50 percent of utility compliance costs because they have low marginal cleanup costs. The Department feels this is fair. DOE does not believe these states will have a disproportionate cleanup burden, since these states are responsible for most of the utility pollution but will pay for only half the cleanup costs. Clearly, the cost of compliance is being spread beyond the ten states and, therefore, there is an element of cost sharing built into the President's plan.

The distribution of allowances to the largest polluters was intended to provide an incentive for these companies to clean up and to earn revenues from the sale of surplus allowances. For many of these units compliance cost will be significantly lower than average. These units will be able to overcontrol and earn revenues from the sale of excess allowances. Since utilities desiring to grow will have to obtain allowances and the dirtiest units will have most of the allowances, owners of these dirty units undoubtedly will reap some gain from the initial allowance distribution. This scheme, therefore, has a measure of cost mitigation built into it. Additional cost sharing measures are unnecessary and inequitable to those companies that already have paid their fair share of prior cleanup.

Another argument is that electricity rates will skyrocket in the ten states and that ratepayers will be asked to shoulder too heavy a burden. Again, let's look at the facts. The following table indicates typical monthly residential electric bills at the 750 KWh level in 1988 in the ten states with the highest emission reduction requirements.

	$/Month	Ranking*
Kentucky	$39.81	5
Tennessee	43.01	6
West Virginia	47.11	12
Georgia	49.49	19
Alabama	49.79	20
Illinois	50.89	23
Missouri	52.39	26
National Average	57.39	
Indiana	58.49	33
Ohio	61.09	39
Pennsylvania	63.09	43

* Ranking of "1" represents lowest bill; ranking of "51" represents highest bill.

It is clear from this table that most of the Midwest pays electricity bills that are less than the national average, perhaps because not all pollution costs have been internalized in this region, while utilities in other regions have had to internalize their pollution control costs leading to higher electricity prices.

What about the future? EPA estimates that with a well-functioning allowance system, nationwide average rate increases due to cleanup costs would be in the 1-2 percent range. For the ten states, on a state-by-state basis, the rate increases range as follows:

	2000 High-Low	2005 High-Low	2010 High-Low
West Virginia	5.6-5.1	5.4-4.8	6.0-4.7
Ohio	4.1-3.5	4.3-3.2	4.7-3.3
Indiana	3.8-3.6	4.0-3.8	4.7-4.0
Pennsylvania	1.5-1.5	2.0-1.6	2.0-1.4
Georgia	1.8-1.5	1.5-3.0	2.1-1.9
Missouri	4.4-3.9	3.9-4.5	4.0-3.6
Illinois	0.8-0.1	1.4-2.9	2.1-0.7
Tennessee	2.2-2.2	2.4-2.4	2.8-2.2
Kentucky	3.5-3.1	3.4-3.9	3.6-3.1
Alabama	1.1-1.1	0.9-1.2	1.5-0.7
National Average	1.5-1.2	1.7-1.8	1.9-1.2

The range within each time period represents high and low emissions cases. As the table indicates, there is quite a bit of variability among the ten states with only some of them at the high end of rate increases. Even with these projected rate increases, many of the ten states will still have rates that are below the national average. Again, we do not see any unfairness in the President's plan.

Federal Facilities

The federal facility provision of S. 1630 requires federally owned facilities operating in affected utility service areas to install electric energy conservation improvements and to utilize renewable and alternative clean energy technologies to satisfy at least 10 percent of each facility's electricity needs. While the conservation requirement is burdensome, the renewable and alternative clean energy requirement could require the installation of new technologies at federal facilities that would increase the current cost of electricity by several multiples. If federal facilities could meet the 10 percent requirement by purchasing electricity from nonfossil sources, the requirement would shift nonfossil power from existing customers to federal facilities and fossil capacity previously used by federal facilities to nonfederal facilities. Little would be gained from this reshuffling of power usage, and it may not be feasible, given the integrated electricity grid from which most federal facilities purchase electricity. As an example of the cost burden imposed, the Department of Energy's uranium enrichment facilities would be required to purchase up to 500 megawatts of electricity per year from nuclear power plants, the least costly alternative, with an estimated annual cost of $100 to $200 million per year.

CONCLUSION

The President has proposed an acid deposition control plan that relies upon harnessing the power of the marketplace to achieve the least costly, most effective way to control acid deposition. It relies upon an emissions cap to provide certainty to the system. It relies upon an allowance trading system that imparts fairness, flexibility, and cost effectiveness to the plan. It relies upon an equitable distribution of cost sharing to make sure that no one region pays more than its fair share of the pollution cleanup costs. I urge this Committee to support the Administration's acid deposition mitigation plan, and to correct the deficiencies in S. 1630 relating to lack of clean coal technologies incentives, advanced deadlines, changes in the nitrogen oxides provisions, and the coverage of federal facilities. I am available to respond to your questions.

Public Utilities Commission of Ohio Policy Resolution

on

Emissions Trading Within Federal Acid Rain Legislation

WHEREAS, the Public Utilities Commission of Ohio believes that emissions trading offers an effective means of implementing least cost options to achieve environmental objectives; and

WHEREAS, the Public Utilities Commission of Ohio believes that an emissions trading scheme under which those utilities with higher incremental compliance costs could purchase additional increments of compliance from those with lower incremental compliance costs offers potential economic benefit to Ohio in its efforts to reduce emissions of SO2; and

WHEREAS, it is the view of the Commission that emissions permits will have a limited life of economic vitality as existing "dirty" plants are retired or retrofitted, as new technologies are implemented which will reduce emissions, as new plants meeting new source performance standards are brought on line, and as conservation and demand side management measures are implemented; and

WHEREAS, we believe that, absent unreasonable administrative actions, the concept of emissions trading is workable and beneficial; now, therefore, be it .

RESOLVED, that, under an emission trading system, Ohio's regulated utilities which exceed the minimum required reductions, or, in effect, "overcomply" with the law, would not be penalized by this Commission for their overcompliance where their incremental costs of overcompliance are less than the costs of compliance for potential emissions permit trading partners, where there is a reasonable probability of an overall benefit, both in terms of efficiency and the environment, and where the costs of overcompliance are not excessive relative to the costs that other emitters would incur in complying themselves; and be it further

RESOLVED, that it shall not be the policy of the Commission to encourage utilities to hoard the permits earned, but rather to best utilize them to reduce the overall costs of complying with clean air requirements and to assure that Ohioans maximize the economic benefits from permits during the limited time window in which the permits will be tradable and of economic benefit.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Jolynn Barry Butler

Jolynn Barry Butler, Chair

Ashley C. Brown

Ashley C. Brown   Gloria L. Gaylord

Richard M. Fanelly

Richard M. Fanelly   Lenworth Smith, Jr.

ACB:bj

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The **Chairman**. Thank you very much, Ms. Stuntz.

And by the way, for members of the committee, we have asked Ms. Stuntz and Assistant Administrator Rosenberg to be with us on all three panels. And we appreciate the tremendous investment in time and effort which you unwillingly or willingly are putting in on this.

Senator **Bumpers**. Mr. Chairman.

The **Chairman**. Yes, Senator Bumpers.

Senator **Bumpers**. Mr. Chairman, it would really be helpful if everybody will put the microphones as close to their mouth as they can get them so that everybody can hear.

I could hear you okay, Ms. Stuntz, but it is much clearer and frankly more entertaining if it is a little louder.

The **Chairman**. Next, we are glad to welcome William G. Rosenberg, Assistant Administrator for Air and Radiation of EPA.

Bill.

STATEMENT OF WILLIAM G. ROSENBERG, ASSISTANT ADMINISTRATOR, AIR AND RADIATION, ENVIRONMENTAL PROTECTION AGENCY, ACCOMPANIED BY ROB BRENNER

Mr. **Rosenberg**. Thank you, Mr. Chairman.

We have submitted detailed testimony and also answers [1] to detailed questions for the record.

I certainly sympathize with the task of each senator to master this bill in this area. I have been working on it almost full-time since February and I have brought my assistant, Rob Brenner, to help me answer any detailed questions that are necessary if they come up.

Mr. Brenner is the Director of Policy for our office.

I have divided the testimony into the areas you requested. The first part is to essentially talk about the overall trading system; and the second part would be dealing with some of the equity issues raised by some of the other senators. And so, by not mentioning them first, it is not that we are not planning to talk about them later.

I would like to refer the members to the letter the President sent last Friday to the leadership, both to Senator Dole and Senator Mitchell, which is attached to my testimony. And I will quickly summarize the letter, because it does touch on many of the issues that some of the senators raised, before going into some of the specific testimony.

The President made really five points relating to this bill, which of course was generated in part by his comprehensive proposals to the Congress last summer.

The first goal and test of balance and reasonableness he thought it would be necessary for a bill to be enacted by the Congress would be that environmental protection afforded by the Administration's bill must be preserved and maintained over time.

The second test that he proposed is that the bill should not impose aggregate costs on the economy that exceed the already considerable cost embodied in the Administration's bill, taking into account a 10 percent adjustment for additional amendments tacked on, on the House side.

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[1] See Appendix I.

The third test that he thought was relevant was that controls on the bill should be designed to achieve reductions in the most cost-effective way, that is, the least cost per ton. And that is why we have proposed this trading system.

The fourth point was that the system of emissions trading which allows acid rain reductions to be achieved in the least costly and most equitable fashion be allowed to work without restrictions in the trading system itself.

And finally, that the legislation not include a national electricity tax to pay for controls which would penalize consumers in those states which have already undertaken reductions by making them pay twice for the clean air.

So the President's detailed letter I believe has been made available to all the members.

In that regard I would like to just go through three charts to summarize my testimony.

The first really relates to the acid rain problem and why an aggressive response was needed. As Senator Rockefeller said, thousands of lakes and streams in the United States and Canada have become damaged or threatened.

Dr. Mahoney I am sure will go into that in greater detail, so I will not discuss it at this point.

In addition to the aquatic problems, more than 50 percent of the eastern visibility impairment is due to SO_2.

And I might point out that EPA, within the last couple of months, has made a finding at the Grand Canyon that the visibility impairment in the wintertime at Grand Canyon was attributable to a powerplant adjacent to Grand Canyon.

The SO_2 that is emitted from the plants combines in the atmosphere to form small particulates called sulfates. And they not only have a health problem and an environmental problem, but there is a substantial visibility problem, and we are now in a rulemaking process to determine what to do about the Grand Canyon situation.

So the visibility impairment is not simply an eastern issue.

Sulfur-dioxide and sulfates have shown to cause damage to building and monuments. Forests, and particularly high-elevation forests have been threatened. And increasingly, we are becoming concerned and the Clean Air Scientific Advisory Committee is concerned about the potential for human health risks. And we think that that is an underlying reason to undertake the aggressive response.

The President did propose, and we are pleased to say that the environmental goals proposed by the President were adopted by the committee, both a 10-million-ton bill, a cap to assure that loadings in the atmosphere do not increase with economic growth. And we believe that there is no incompatibility between economic growth and pollution control, which I will talk about in a moment is shared by the Senate Committee.

The Senate Committee in this particular area, unlike some of the other areas, Senator Nickles and Senator Domenici mentioned, did essentially follow the administration's proposals with the changes that Mrs. Stuntz mentioned. But as for the bulk of the bill—we estimate that our bill would cost 4.1 billion a year. The acid rain portion we estimate would cost 4.4 billion, which in the context of this bill is darn close.

The next point I would like to make is the requirement and what would happen if you did not have a cap from an environmental point of view. I know we will be talking about from it a ratemaking point of view. But if in the year 2010, which is the year we tend to look at, as this bill is going to be implemented principally beginning in 2000 and 2003. So, the best date to look at—in the year 2010, the requirement under the bill would achieve approximately 9 million tons of emissions from utilities. It moves a little bit from 2005, goes down a little bit; it comes back up.

So, roughly what we are seeking to do in this bill is to reduce the overall emissions from utilities which were about 16—well, reduce them down to 9 million tons. If we did not have a cap in the year 2010, all the growth above the line would occur, so that essentially there would be a 10 percent to potentially 30 percent degradation in the amount of SO_2 that would be put in the atmosphere without a maintenance of the cap.

And so if we are going to spend all this effort and money to get the environmental protection levels, to get the SO_2 levels to achieve the environmental protection, from an environmental point of view we think it is very important to maintain those levels by assuring that any growth in emissions be offset by a comparable amount of decline so, that the level of utility emissions would remain constant at about 9 million tons.

Now, that raises the obvious question: is the growth cap an economic cap? And that is one of the big issues raised by the Senators. I think that we need to look a little bit at history in this regard, because what we have seen since 1970 is indeed a growth in electricity sales, which are up 76 percent, a growth in the GNP which is up 59 percent, indeed a 50 percent growth in coal use since 1970, and yet there has been a net decline of 28 percent in SO_2 emissions. So that, to date, certainly, a clean environment does not mean less economic growth.

And the reason for this is that to achieve the decline in emissions in the face of growth, there is really two things that could be done. The fuels that are used could be cleaner. And the technology that would be employed would also improve. And the effort has been made in this bill to provide technologies, to provide incentives to do both: to promote the use of cleaner fuels, whether that is lower sulfur coal or natural gas, or in the area of automotive fuel, a cleaner gasoline and other alternative fuels.

Senator **WALLOP**. Mr. Rosenberg, forgive me. When you say this bill, would you distinguish between bills. Are you talking about the President's bill or the one which——

Mr. **ROSENBERG**. I am talking about the President's bill. Thank you, sir. I should be very clear on that. Although many of these provisions as relate to acid rain are very consistent in the Senate Bill. This is the one area where the Senate Committee really adopted most of the President's proposals. In the other areas they went way beyond them, in the air toxics area and in some of the nonattainment areas.

The final point is that we think that the trading system itself will promote the development of new technologies, so that as we have growth, we can still make the environmental progress we seek to have. And that is exactly what has happened in the past. And we would second the Department of Energy's concerns about putting in the incentives that were in the President's proposals for clean coal technology, both utility rate-making incentives and environmental streamlining—environmental improvement.

We do believe that the trading system and the incentives will stimulate further use of coal, continue to allow those trends in electricity growth, in GNP and coal use to go up, and then stimulate the trends of SO_2 emissions to go down, so that we can have economic growth and a cleaner environment and healthier air.

At that, sir, I will end the discussion until there are questions. Thank you.

[The prepared statement of Mr. Rosenberg follows:]

TESTIMONY OF
WILLIAM G. ROSENBERG
ASSISTANT ADMINISTRATOR FOR AIR AND RADIATION
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

January 24 and 25, 1990

Mr. Chairman and Members of the Committee, I am pleased to appear before you to discuss the energy policy implications of S. 1630, the "Clean Air Act Amendments of 1989," the legislation amending the Clean Air Act which was ordered reported by the Committee on Environment and Public Works on November 16, 1989.

We have made great progress in breaking the stalemate that has stalled reauthorization of the Clean Air Act for years. On July 21, 1989, the President unveiled his legislative proposal to deal with the persistent air pollution problems of this country. As you know, the President's proposal, which was the first piece of legislation to offer comprehensive revisions to the Clean Air Act since 1977, is designed to curb three major threats to the nation's environment and to the health of millions of Americans: acid rain, urban air pollution, and toxic air emissions. The Senate is to be commended for the development of a comprehensive bill, S. 1630, that is now ready for consideration on the floor of the Senate. Although there are a number of important differences between the President's clean air proposal and S. 1630 that the Administration does not support, there are many features which are similar. Without a doubt, any proposal of such magnitude certainly contains energy policy implications for the country; it is appropriate for this Committee to fully examine such implications more closely.

As the President indicated in a letter which he sent to the leadership just last Friday, the comprehensive Clean Air Act amendments package which he has proposed is designed to achieve a balance of environmental and economic objectives through the use of market forces, thereby meeting our environmental goals at the lowest cost to the economy and consumers. In addition, the President's proposal promotes favorable energy policies. Opportunities for use of natural gas would be plentiful as a result of the reductions required in the acid rain program and the use of natural gas in the manufacture of MTBE, an oxygenated fuel used as a motor fuel additive to reduce both hydrocarbon and carbon monoxide emissions, and in compressed natural gas. Furthermore, the proposed acid rain control program would encourage the use of lower sulfur coal. By permitting freedom of choice, both in the selection of fuels and technology, the President's proposal would shift the emphasis away from the "command and control" approach of the 1977 Clean Air Act.

The President's proposal also encourages the development of clean coal technologies which would allow the use of many energy sources in an environmentally acceptable way. The Clean Coal Technology program would foster the development and demonstration of technologies which would allow the continued use of coals of varied sulfur content, thereby ensuring that coal from all regions of the country would be available for use in meeting acid rain requirements. The market-based trading system which the

Administration has proposed would leave to industry the choice of compliance options: the legislation sets the objective and allows each company to make its own economic choices in determining how to meet those objectives.

The President is also challenging industry in his alternative fuels program. The President believes that it is time to have cleaner cars operating on clean fuels. I have testified before this Committee on the President's program and rather than repeat my testimony here, I have attached it and ask that it be incorporated in the record as part of my testimony today. As we have stated before, our proposal is balanced and is completely fuel and technology neutral. It would allow all clean fuels--natural gas, ethanol, methanol, propane, LPG, electricity, and reformulated gasoline--to compete in the marketplace. This clean fuels program would complement the Alternative Motor Fuels Act of 1988 drafted by Senator Rockefeller and Congressman Sharp.

As I understand the structure of this hearing, there are three separate panels, each of which will address different specific aspects of the energy implications of S. 1630. Accordingly, the testimony which I am submitting for the record will be divided into three parts.

I. PANEL ONE

The purpose of this panel is to explore the energy policy considerations relating to the emissions cap, the allowance trading system, and cost sharing under the acid rain provisions of S. 1630.

As President Bush has eloquently stated earlier this year with regard to acid rain, "the time for study alone is over. The time for action is now." Sulfur and nitrogen oxide emissions are transformed in the atmosphere to form compounds that threaten our lakes and streams, forests, buildings and monuments, visibility and health. Substantial reductions in these pollutants will cost billions of dollars. The purpose of both the President's acid rain proposal and S. 1630 is to achieve environmental goals in the most cost-effective manner, and S. 1630 adopted many aspects of that proposal.

S. 1630 and the President's proposal each call for permanent reductions of sulfur dioxide emissions of 10 million tons from 1980 levels. Additionally, they are very similar on the major issues of the reliance on a market-based approach, the requirement for emissions offsets for new sources, and the absence of cost-sharing in the form of fees or taxes. On the question of timing, the Senate bill implements Phases I and II one year earlier than the Administration bill, but keeps the repowering extension date of December 31, 2003. I believe that the Phase I and II compliance dates must not be moved up because that will limit the compliance options available to companies.

In addition, S. 1630 deals with two other issues. First, by providing allowances at 120% current emissions for all clean sources (less than 1.2 lb. SO_2/ mmBtu), S. 1630 would provide a cushion for cleaner sources to grow before having to purchase offsets. It would also assure that upon retirement of these sources, allowances would become available for new sources, thus ensuring that a nationwide electric utility SO_2 emission cap of 8.9 million tons per year would be maintained. Second, S. 1630 also responds to concerns of growth States and independent power producers that allowances would be hoarded by including a provision which would allow EPA to withhold 2% of the allowances and sell them if new sources cannot find them through the market.

The Administration urges the members of this Committee to support an approach containing these basic elements and to back the proposal to achieve and maintain a ten million ton reduction and the resulting environmental improvements. An acid rain control proposal with the innovative emissions trading program I will describe below will be the test case. With it we will demonstrate that a regulatory program which is flexible, accountable, and enforceable can protect and improve environmental quality and support long-term economic growth.

In structuring a solution to the acid rain problem, the President remains firmly committed to several principles: the desirability of the ten million ton reduction target, the necessity for the permanent cap on emissions, and the appropriateness of the market-based approach. The President is opposed to cost-sharing through fees and subsidies.

The President also believes that total costs of an acid rain solution should be minimized, and costs that are incurred should be distributed as fairly as possible, both through the initial allocation and through the operation of the emission control effort. Both the President's acid rain proposal and S. 1630 work to minimize and fairly distribute the costs of SO_2 emissions reduction. First, they establish that it is the proper role of government to protect the air and to set standards for its use, in this case by establishing an allowable emissions limitation. These are not "pollution rights," but as the word says, "allowances."

Second, the initial allocation of these allowances, which require high emitting sources to reduce emissions to 1.2 lbs. of SO_2 per mmBtu but permit clean sources below 1.2 lbs. to continue emissions at current levels, is generally accepted as a good approximation of a "least-cost" solution. Therefore, even before extensive emission trading the proposals are reasonably cost-effective.

Third, the approach used in these bills makes it clear that if we are to meet this challenge of reducing acid rain in the least expensive, most cost-effective way, then we must involve the creative, innovative energies of the affected industries. This recognition, and its incorporation into legislation, marks a shift in the direction of environmental protection from that of the past 20 years where the response to environmental problems has been increasingly more specific direction from the federal government in the form of "command and control" regulations. The new approach in our proposal gives industry a great deal of flexibility in meeting the allowed emissions level. And it provides economic incentives to employ the least-cost solution by choosing among cleaner fuels, pollution control technology, energy efficient combustion and the promotion of conservation. Every ton of pollution that is prevented means one less allowance a source needs to buy, or one more allowance a source can potentially sell.

Fourth, the simplicity of the allowance system greatly facilitates the transfer and banking of allowances and, based on our analysis, should reduce the cost to ratepayers by $1 billion per year or at least 20 percent over conventional trading schemes. Emissions trading without an allowance system would often be a cumbersome and contentious process, because of the need to negotiate, on a case-by-case basis, the "baseline emissions" for each of the trading participants, the precise effect of the controls of all participants, and the need to go through lengthy State and federal environmental rulemaking processes to complete a trade.

With the allowance system, the basis for emissions trading is established by the statute. Boilers would be issued annual emission allowances based on the product of reported fuel use and the emission rate stated in the bill. Allowances would then be available for transfer between affected facilities.

The parties to an emissions trade would simply notify EPA that they had negotiated a trade--an "allowance transfer". EPA would record the transfer within a few days in much the same way that a bank debits and credits two checking accounts when a transfer of funds is made.

The sources would not need a new air permit each time they transfer allowances, just as one does not need to open a new checking account each time one writes a check. The permit would simply state that the source may not emit more tons of SO_2 in a year than the allowances it holds for that year.

The allowance system will also authorize banking of unused allowances, thus not penalizing prudent control decisions that build in a margin of safety. Other legislative proposals have not allowed this.

To ensure that the bills' objectives are met, all sources in the system would monitor and report their emissions periodically as a condition of their permit. Failure of any source to stay within its annual emission allowances will subject it to an automatic fee of $2000 per excess ton and a statutory requirement to offset those excess tons the following year.

Our bill and S. 1630 are the first major efforts to incorporate market mechanisms in an environmental protection statute--to rely on the market to balance the nation's environmental and economic objectives. Many of the objectors to the market-based system have complained that our approach is too novel and risky. I disagree. The market has played a central role in the U.S. economy for over 200 years. Markets imply competition and competition implies risk for those that participate. But markets also imply creativity, choice, efficiency and responsibility.

Tapping the market to implement the acid rain control program provides us the ability to achieve our goal of environmentally sound energy supply at a lower overall cost. The Administration's proposal has not attempted to change the nature of energy markets, but rather to ensure that the environmental costs of each supplier are fully internalized. Thus, our system actually corrects a market failure associated with the externalization of pollution costs in a way that minimizes government intervention. Furthermore, as I will explain in the part of the testimony prepared for Panel II, our proposal is pro-coal because of the incentives which it includes for the development of clean coal technologies.

It is the combination of the flexibility of the emissions trading provision and the certainty of the emissions cap that allowed us to come forward with such a far-reaching proposal. Not only is the cap integral to the goals of the legislation, it is technically and economically feasible and necessary for the entire program to work as designed.

Beginning in 2003 when the last existing boilers come into compliance with the acid rain reduction requirements, the utility industry as a whole will be emitting roughly 8.9 million tons of SO_2 annually. By that time we expect that new coal plants will be achieving 95 percent sulfur dioxide removal or emitting at rates of about 0.3 lbs per mmBtu in the East and substantially less in the West. Over time, as existing units retire, their allowances will be transferred to new units needing far fewer allowances per unit of installed capacity. Or, to put it another way, as we build cleaner and cleaner coal-fired units, more and more new units could be constructed. The same 8.9 million tons of annual SO_2 could support three or four times as much installed new fossil-fuel fired capacity. Thus an emissions cap is not a growth cap.

Utility strategies to comply with this law will undoubtedly include a combination of controlling and retiring older plants, using cleaner fuels, managing the growth in energy demand, and building the most efficient new plants possible. Each company can find the best combination of the use of control measures and clean fuels for its particular system.

The allowance system allows companies to comply with their reduction requirements on a system-wide basis and to adapt their strategies, both as long-term needs change and in response to unexpected problems, such as equipment breakdowns, without lengthy government rulemaking. Pollution minimization will at last be fully integrated with cost minimization in utility planning. Utilities that manage their growth in demand will benefit by avoiding the need for SO_2 allowances. Utilities that successfully design and operate equipment with high efficiency and high pollutant removal levels or who use cleaner fuels will be successful in this new regulatory climate. Pollution prevention and new pollution control technologies will work together to help utilities meet new legislative requirements.

Unfortunately, the conservation, innovation and efficiency incentives inherent in our proposal disappear or are severely diminished without the emissions cap. If new sources are allowed to be constructed without obtaining offsetting reductions, utilities have little incentive to advance the state of the art in clean generating and pollution control technologies or manage demand growth, and the environmental protection achieved will be undermined.

The cap and allowance trading system also tend to share the economic burden of acid rain control throughout the country over time. The bill does require the polluter to pay for the initial clean up: those with the highest emission rates will be required to reduce their emissions the most without benefit of a subsidy from those with lower emission rates. In fact, nine States (Pennsylvania, West Virginia, Ohio, Indiana, Illinois, Missouri, Kentucky, Tennessee, and Georgia) which emitted 50% of this Nation;s SO_2 in 1980, will be required to reduce their emissions by 65%. But because high emitting plants are often the least expensive to control, these nine States will be paying about 50% of the cost of control--the same level as their contribution to the problem.

Despite the fact that new sources will be encouraged to minimize emissions, in some areas there will still be emissions growth. When these new emissions cannot be covered by that company, the bill allows the new source to obtain allowances from anywhere in the country. This means that areas whose emissions continue to grow will pay areas that have the least expensive emission reductions to sell, thereby reducing overall costs in those areas with allowances to sell, typically the Midwest and the Southeast.

By being able to obtain allowances from anywhere in the country, we are providing a much larger market than current offset requirements under the nonattainment provisions of the Act which limit the market area to the same metropolitan area. Also, new sources would have a choice of where to obtain offsets, rather than being limited to obtaining them from nearby competitors. The result should be offsets available from dozens of sources and at competitive prices. (For a further discussion of the competitive marketplace for allowances, please see Richard Schmalensee's testimony of October 11, 1989 before the House Subcommittee on Energy and Power, as well as the Department of Energy's testimony for this hearing).

It has been pointed out that neither of these bills mentions the role of State and federal utility regulatory commissions in the allowance trading system. That omission is not an oversight. State and federal public utility regulatory bodies are not mentioned because the legislation is not proposing to change their roles. Over the past two years, EPA has worked with the National

Association of Regulated Utility Commissioners exchanging ideas and perspectives on potential acid rain control program implementation problems and solutions. These discussions revealed that acid rain legislation should minimize any interference with the utility regulatory process, and if possible, try to build on its strengths. By internalizing environmental costs and by not prescribing specific actions States would have to take, but by allowing adequate time to incorporate State specific needs, I believe the implementation of this legislation will be compatible with the State and federal regulatory processes.

In fact, the actual costs of this program will be determined by the decisions of both utility companies and their regulators as they scrutinize pollution control costs and assure that allowances are fairly priced, both for buyers and sellers. That is why the Administration was particularly gratified to see the enlightened response of the Ohio Public Utility Commission to the trading of emissions allowances. In their resolution of January 4, 1990 they recognize the many benefits of an allowance trading system and encourage utilities not to hoard allowances but "to reduce the overall costs of complying with clean air requirements and to assure that Ohioans maximize the economic benefits from [allowances]...."

In conclusion, our innovative emissions trading program is simple, flexible, accountable and enforceable from an environmental perspective. It is also workable from a utility regulatory perspective. The marketable system of allowances makes the maintenance of the emission reductions economically feasible, and the cap ensures the full economic and environmental benefits of the market-based approach. Together, they strongly encourage conservation, provide an incentive for the development and deployment of cleaner, energy efficient technologies, and permit the costs of acid rain control to be shared across the country. Most importantly, the approach embodied in this bill ensures that the Nation can continue to have economic growth and prosperity while protecting the environment which we as a people treasure.

II. PANEL TWO

The purpose of this panel is to discuss certain other energy policy considerations of the acid rain provisions which were not discussed in the first panel. These considerations include the clean coal technology program, regional impacts other than cost sharing including the "clean States credits," and the inclusion of industrial sources. I will address each of these considerations individually.

Clean Coal Technology

EPA is committed to the success of the Clean Coal Technology (CCT) Program. It offers our best hope for demonstrating and deploying more efficient, less polluting, and less costly technologies for burning coal-- America's most abundant energy source. In addition to fully funding the CCT program, the

Administration has included in its legislative proposal an economic incentive program to be administered by the Federal Energy Regulatory Commission (FERC) as well as streamlined environmental requirements for CCT demonstration projects. The Administration's proposed modifications to the Clean Air Act are necessary because under current law and implementing regulations, demonstration projects could be treated as new sources and subjected to stringent controls inappropriate to fledgling technologies. Such technologies, in their first applications, may not live up to their full pollution removal potential, or, although able to remove pollutants on a very low dollar per ton basis, would not necessarily meet emission standards intended for new sources.

Through an Interpretive Rule which we plan to issue in the next few months, EPA plans to exempt CCT demonstration projects and other activities which are designed to reduce emissions from certain regulatory requirements. Nevertheless, a legislative change would provide participants in the program more certainty of their status under the law and would extend the exemption to the full range of demonstration projects, such as repowering projects, which might increase emissions because of the increase in generation capacity associated with repowering.

Although S. 1630 recognizes that additional time will be necessary to deploy repowering technologies (extending the compliance deadline for sources choosing to use such technology to December 31, 2003), it does not contain any of the regulatory incentives proposed by the Administration for demonstrating clean coal technologies or for deploying repowering technologies. We believe this is a serious omission and strongly urge the Senate to insert these incentives in their bill.

Regional Impacts

There will be electric rate increases and shifts in coal production under any acid rain bill. We believe that the rate impacts under the President's proposal are the lowest per ton of reduction of any proposal put before Congress. Nevertheless, the President's proposal would increase electric rates for Midwestern and Southeastern ratepayers, as well as for Northeastern and Western ratepayers. According to our analysis of the bill, national rate increases would be 2 to 3 percent through the year 2010, but rate increases for Ohio, West Virginia, and Missouri could exceed 4 percent by the year 2000 and West Virginia's rate increases could exceed 5 percent by the year 2010. Several States in the Northeast, West and South could be expected to see rate increases greater than 1 percent, with some like Wyoming, Montana, Oklahoma, Kansas and Nebraska having increases greater than 2 percent by year 2010.

Individual companies could experience rate increases less than or as much as 2 to 3 times greater than the statewide average. Just as control options and costs can be expected to vary greatly from one utility to another, utility rates have historically varied greatly. There are many reasons for this, including cost of fuel, prudence determinations, cost of previous investments, management skills, and pollution control expenditures.

Rates have been low for several companies because they have used cheaper, high sulfur coal and have not needed extensive pollution controls. An example is Ohio Power, whose rates are 35 percent below the utility industry average and substantially below the rates for other utilities in Ohio. Under most acid rain control proposals, Ohio Power's plants offer some of the most cost-effective control opportunities in the State and, therefore, several of their plants likely would be controlled. Even if the percent increase in that company's rates were substantial, its rates would still be lower than those of other operating companies in the State and well below the national average.

On the other hand, in States like New York, New Jersey, and Connecticut, where 85 percent of the customers pay rates ranging from 112 percent to 178 percent of the national average, a one percent regional increase would still keep the cost of electricity in those State well above that in West Virginia, Kentucky, Indiana and Ohio.

What the President's proposal offers that others do not is the flexibility to keep rate increases to a minimum. Based on our analysis, the President's approach can achieve the necessary emission reductions at the lowest possible cost -- at least 20 percent cheaper or $1 billion annually than without such a simple, flexible trading system. The Administration does not believe, however, that it is reasonable, necessary, or fair for areas with lower emissions (that is, those using more expensive, lower sulfur fuels or scrubbers) and generally higher utility rates to subsidize those areas needing to reduce emissions.

We have estimated the employment impacts due to reduced use of high sulfur coal at 5,000 to 7,000 reduced jobs slots in the first phase and 15,000 to 17,000 reduced jobs slots in the second phase. Growth in high sulfur coal markets resumes after year 2001 as new coal plants are built and existing plants repower with clean coal technology. The high sulfur jobs lost are offset by low sulfur coal mining jobs of 19,000 to 21,000, created mostly in central and southern Appalachia. I do appreciate, of course, that the difficulties and costs of relocation do not make this a solution to the loss of jobs in the high sulfur coal industry.

This Administration believes that the primary way to mitigate the loss of high sulfur coal jobs is to expedite the development of technologies that can make use of this country's abundant coal resources. This will not only maintain jobs in the coal mines and the communities they support, but provide new jobs in technologies with world-wide demand. Compared to other bills, our bill offers the most aggressive incentives to develop and deploy these technologies, providing a meaningful and permanent response to this important concern.

EPA is in the process of completing our analysis of S. 1630, which will include electric rate impacts and coal market impacts by State, and will make it available as soon as it is complete. However, considering its similarity to the Administration proposal with regard to sulfur dioxide reductions, I can say that the impacts will be similar to those estimated for our bill with two notable exceptions--the "clean States" provision and the NOx requirements.

The "clean State" provision would exempt from control requirements those States with 1985 utility SO_2 emission less than 150,000 tons which have over 50% of their coal-fired generation from scrubbed units. Accordingly, it would exempt Kansas, Minnesota, North Dakota, Montana, Wyoming, New Mexico, and Utah from SO_2 reductions at all existing pre-enactment sources; however, it would not exempt these States from new unit offset requirements for NOx emissions.

EPA does not believe this provision is equitable for two reasons. First, it essentially would exempt certain high emitting sources from control because they happen to be in States where other units are scrubbed. Lower emitting sources which happen to be in States with less scrubbed capacity, however, would have to reduce their emissions. Second, States with very low emission rates, because of reliance on cleaner, and often more expensive fuels such as gas, low sulfur oil, or nuclear power would also not be exempted.

The effect of the "clean State" provision would be to lessen SO_2 emission reductions by 200,000 to 300,000 tons per year and reduce compliance costs in these seven States.

S. 1630 increases the NOx reduction requirements over that of the Administration proposal. Because the marginal costs of NOx control increase rapidly after the first 2 million tons of reduction, the larger reduction required by S. 1630 will be significantly greater than the costs imposed by the Administration proposal. Therefore, we oppose the NOx provisions in S. 1630.

The Administration also objects to the federal facility provision of S. 1630. The renewable and alternative clean energy requirement could require the installation of new technologies at federal facilities or shift electricity purchases to more expensive suppliers. In either case, the cost burden on the federal government could be substantial.

Inclusion of Industrial Sources

The Administration does not believe that industrial sources should be included in the proposed acid rain program for four reasons. First, industrial facilities are consumers of electricity and therefore would be paying their share of electricity rate increases. Second, many industrial facilities are required to reduce pollution under Title I (nonattainment) and Title III (air toxics) of the proposed amendments. Third, it would be impractical to include them because there are about ten times as many industrial facilities as there are utility boilers; many have dozens of emission points. And there are numerous categories of industrial sources, each requiring different control approaches.

Moreover, in the aggregate, industrial sources emit less than half the emissions of utility boilers. Therefore, administrative and compliance costs per ton removed, in many cases, would be higher than for utility sources. Fourth, if the bill were to exclude the smaller and cleaner facilities from requirements, as was done for utility boilers, there would be few emission reductions gained by the mandatory inclusion of this category. However, since there are opportunities for cost-effective SO_2 reductions scattered throughout the industrial sector, the Administration and Senate proposals allow sources to elect into the allowance system.

PANEL III

The purpose of this panel is to discuss the impacts on the electric utility and oil and gas industries of the nonattainment and air toxics provisions contained in S. 1630. For the sake of clarity, I will focus my comments on the provisions of those sections of S. 1630 which differ from the Administration's proposal and could have an adverse impact on the industries which are of concern to the Committee.

Nonattainment Issues

In the nonattainment title, we are particularly concerned about the provisions of S. 1630 which affect the definition of "major source", provisions regarding offsets and netting, provisions regarding area designations, and provisions that affect motor vehicle fuels. The nonattainment section of S. 1630 also contains other provisions which differ from the Administration proposal in troublesome ways. These include: provisions regarding stationary source fees, a provision establishing a Northeast Ozone Transport Region, and a provision regarding VOC emissions from consumer/ commercial products. Although many of these provisions are highly technical, each could have a significant impact on energy industries.

The Administration's proposal retains the current definition of "major source" (100 tons per year), while S. 1630 lowers the definition to 25 and 10 tons per year in areas with higher ozone levels. Although we have no detailed information on oil and gas facilities per se, examination of available source sizes show that reducing the cutoff from 100 tons per year to 25 or 10 tons per year increases the total number of existing sources affected by permitting, fees, and RACT by threefold to fourfold. It is certain that the number of smaller utilities and particularly oil and gas production facilities affected by these provisions would be significantly greater under the Senate bill than under the Administration bill. Even natural gas pumping stations could become "major sources" under the reduced cutoffs. However, the large increase in potential sources affected would not likely result in a proportional increase in emissions reduced. Again, we do not have specific estimates for the oil, gas, or utility industries, but, for example, in going from a 100 tons per year to a 25 tons per year cut off, the number of sources of volatile organic chemicals (VOCs) goes up by 300%, while the potential VOC emissions covered go up by only 15%. In short, there would be no comparable environmental benefit compared to the costs imposed on these smaller sources.

The Administration bill requires new and modified major sources to offset emissions increases with reductions at existing sources. A source which makes a major modification can "net" out of new source review by previously reducing emissions elsewhere within the plant. This allows growth without adverse effects on air quality. By contrast, the Senate bill would eliminate "netting". Moreover, the Senate bill would require new sources to offset emissions by reductions that are proportionally greater than the increase (e.g. 1.5 to 1 or 2 to 1 ratios). Moreover, S. 1630's "major source" definition would subject many more smaller new or modified sources to higher offsets and a requirement to emit at the lowest achievable emissions rate (LAER). These Senate provisions would likely make it harder to expand existing oil and gas production and refineries; they would also make new utility construction in nonattainment areas more difficult. The Administration position would be substantially more flexible and would still afford ample protection with respect to the air pollution impacts of growth in the energy sector.

Concerning area designations, the Administration proposal would retain the current practice of allowing States to designate the boundaries of nonattainment areas subject to EPA review.

S. 1630, however, would require expanded boundaries to include at least the MSA/CMSA. To exclude an outlying portion of a CMSA (perhaps containing a utility or oil or gas field), a State would have only 60 days to prove that the facility did not contribute to the nonattainment problem. Exemptions would be very difficult to obtain since it would be difficult to demonstrate no contribution whatsoever to the nonattainment problem. Moreover, sixty days is too short a time, and could result in including areas larger than necessary for attaining standards. Thus, existing sources currently in attainment areas would face unnecessary RACT requirements and new or modified sources would face unnecessary LAER and offset requirements.

The nonattainment title of S. 1630 and the Administration proposal contain provisions which affect motor vehicle fuels, and, therefore, the oil industry. Both bills would require further reductions in the volatility of gasoline, that is, the tendency of gasoline to evaporate on hot summer days. The levels of sulfur in diesel fuel used in on-highway motor vehicles would be reduced, thereby allowing diesel trucks and buses to comply with EPA's standards for emissions of particulate matter. Both bills include requirements that certain cities must implement programs to use oxygenated fuel blended with gasoline during the winter months to reduce emissions of carbon monoxide from cars and trucks. S. 1630 requires an average oxygen level of 3.1% in CO nonattainment areas. In contrast, the Administration's bill requires the five cities with the worst CO nonattainment problems to use fuel with an oxygen level that would result in attainment, thereby leaving the choice to each area. S. 1630 would ban the use of leaded gasoline in highway vehicles beginning January 1, 1991. It also required EPA to promulgate within three years regulations concerning fuel quality.

The Administration bill includes a bold and innovative program to introduce vehicles capable of operating on clean, alternative fuels in the nine cities with the worst air pollution problems. One of the major drawbacks of S. 1630 is that it does not include a provision for a clean fuels program. Rather, under the Senate Tier 2 tailpipe requirement, it would mandate the addition of more emission control equipment on all new cars sold across the Nation beginning in 2003 which the Administration estimates will cost $500 per car, or $8 billion nationwide. This approach achieves fewer environmental benefits at a slower pace and is much more expensive than the Administration's approach. The Administration proposal focuses on introducing cleaner cars that burn cleaner fuels in the cities that have the worst air pollution at the lowest cost to the consumer. It would begin in 1995 with cars that have emissions of volatile organic compounds that are equivalent to the Senate Tier 2 standards, but the environmental benefits are realized eight years earlier than under the Senate bill.

The provisions in S. 1630 regarding stationary source emission fees would require much greater fees for emissions of ozone precursors, nitrogen oxides, carbon monoxide or PM-10 than would be required by the Administration proposal. The projected total fees collected under the Senate proposal would be $1.3 billion as opposed to $310 million for the Administration proposal (including both federal and State fees). The Senate bill would require not only a $75 per ton fee from all major sources, but would provide for no cap on the fees which would apply to sources of sulfur dioxide emissions. As explained above, due to the definition of "major source" in S. 1630, many more sources would be subject to these fees. In contrast, the Administration bill provides for a $25 per ton fee on all major sources with a cap off at 4000 tons for sources of sulfur dioxide emissions. Under the Administration bill fewer sources would be subject to the fee provisions and the costs to those sources would be significantly less. In short, the Administration proposal would pose less of a financial burden, especially for small businesses, while still providing the necessary support for State permitting programs.

Concerning ozone transport regions, S. 1630 established a Northeast Ozone Transport Region that is very similar to that established by the Administration bill. Under the Administration bill, however, the Transport Commission recommends appropriate control strategies following an examination of scientific and technical assessment of alternative approaches. The Senate bill, on the other hand, requires imposition of Stage II controls and Reasonably Available control Technology on major VOC sources throughout the region, including ozone attainment areas in which such controls may not be necessary. Based on preliminary photochemical modeling to date, it is very questionable whether such costly controls will produce any significant benefit to areas with serious ozone problems. The Administration approach is the far more likely to result in a cost-effective strategy in dealing with transport.

Finally, both the Administration and Senate proposals require a two year study of the VOC emissions from consumer and commercial products. The key difference between these proposals is that the Senate bill would require EPA to establish regulations to reduce 3% of the nationwide total VOC emissions from consumer/ commercial products. The Administration position, however, would base any reductions in VOC emissions from this source category on the results of the two year study. The Senate provision would be costly for the oil and gas industry because the many consumer and commercial products produced by this industry would be subject to an automatic standard to reduce VOC emissions.

Air Toxics Provisions

In addition to the concerns we have outlined with S. 1630's nonattainment provisions, there are three provisions in the air toxics portion of S. 1630 which the Administration believes could adversely affect the oil and gas industry and utilities with no concomitant benefit. The first provision concerns the definition of "residual risk". Both S. 1630 and the Administration's proposal would require sources of toxic air pollutants to apply maximum available technology controls, known as MACT. Both approaches also establish a framework for addressing the risk remaining after the application of MACT. However, the Administration proposal would include consideration of cost, technical feasibility, and other factors for the Administrator to determine if this residual risk is unreasonable. S. 1630 would require that facilities meet a predetermined bright line risk level without consideration of costs or other factors. Although the extent to which this provision in the Senate bill would specifically affect the oil and gas production or utilities industries cannot be determined at this time, we believe that the residual risk requirements of S. 1630 could potentially shut down many facilities and result in extremely high costs to industry in exchange for very small environmental benefits to the public.

The second major difference is of particular concern to the electric utility industry. The Administration proposal would require that EPA conduct a study of the potential health risk, if any, due to air toxics emissions from utilities prior to imposition of any air toxic regulatory requirements on utilities. The reason for this proposal is twofold. First, over the next decade, the utility industry will be faced with substantial compliance costs associated with the implementation of acid rain controls. Second, there is insufficient information at this time to suggest that emissions of air toxics from utilities pose significant public health risks. The study required under the Administration proposal would provide a much-needed opportunity to evaluate any potential health risks from these emissions. Any regulation of this industry under the air toxics control provisions of the Act would then be based on the conclusions of such a study.

This approach differs substantially from S. 1630, which would only provide a three-year exemption from the air toxics standards for chlorine compounds. This provision would still require utilities to comply with air toxic regulations for other pollutants which they emit. Not only would these regulations overlap with the regulations under the acid rain provisions, they would also set up a "two track" regulatory system for utilities which would consider chlorine emissions separately from other air toxics. This could result in one set of controls being applied for the nonchlorine compounds and, three years later, another set of controls for the chlorine compounds (in addition to the controls required for acid rain). Under this provision, the air emissions from this industry could be assessed and regulated three separate times.

The third provision of concern to the Administration which is included in the air toxics section of S. 1630 is the provision regarding leak detection. The Senate proposal includes a provision which would require the owners/ operators of facilities subject to MACT standards under the air toxics provisions to monitor "all devices and systems" to "detect immediately and report concurrently to the facility operator accidental releases." It is not certain that such extensive monitoring is possible, let alone necessary. In many cases, monitoring technologies have not even been developed to detect some of the chemicals on the list. This provision would be extremely costly to the oil and gas industry as well as all of the industries potentially covered by MACT standards.

While the focus of today's hearing has been on the effects of S. 1630 on the utility industry, there is another provision of the legislation on which the Administration would like comment briefly. This is section 111 of S. 1630, which would transfer jurisdiction for Outer Continental Shelf (OCS) air emission regulation from the Department of the Interior (DOI) to the Environmental Protection Agency.

The Administration believes that existing law provides adequate authority for DOI to regulate air emissions associated with OCS oil and gas activities. The Administration opposes the transfer of jurisdiction over OCS emissions from DOI to EPA. Concerns which led to the proposed transfer of jurisdiction come primarily from unique conditions that occur in California. DOI is currently drafting an NPRM to limit air emissions from OCS operations off the coast of California.

* * *

Mr. Chairman, thank you for your invitation to present testimony before this Committee. I would be pleased to answer any questions that you may have.

THE WHITE HOUSE
WASHINGTON

January 19, 1990

Dear Senator Dole:

Last July I submitted to the Congress a comprehensive proposal for reauthorizing and strengthening the Clean Air Act. That proposal was the result of a long and careful debate within the Administration, and reflected extensive consultation with Members of the House and Senate, representatives of affected industries, state and local governments, and environmental and public health groups.

Consistent with my belief that environmental protection and economic growth can be compatible, the Administration's Clean Air bill seeks to achieve public health and environmental protection in an economically efficient way by making extensive use of market principles. My comprehensive proposal carefully balanced our mutual desire for enhanced public health, a cleaner environment, and sustained economic growth. Even so, the cost estimate of the Administration's bill to the American economy is approximately $19 billion annually when fully phased-in.

As the Senate moves toward floor consideration of the Clean Air Act, I am convinced that we must maintain the balance reflected in the Administration's bill. Initial cost estimates of the Clean Air bill reported by the Senate Environment and Public Works Committee exceed $40 billion annually -- more than double the cost of the Administration's bill. Yet the Committee bill provides little incremental environmental benefit above that proposed by the Administration. And the additional costs of some of the Committee bill's far-reaching provisions have yet to be incorporated in these estimates.

I want to sign a Clean Air bill this year -- so that the 1990s can indeed be known as the "Clean Air decade." But I will only sign legislation that balances environmental and economic progress.

Specifically, I will only approve legislation which meets the following minimum tests of balance and reasonableness:

1.) The important environmental protections afforded by the Administration's bill must be maintained in the final legislation and preserved over time. The Administration proposes to: reduce sulfur dioxide emissions permanently by 10 million tons; achieve attainment of ozone, carbon monoxide and particulate matters standards; and sharply curtail the hazards posed by air toxics emissions. These represent critically important steps in achieving clean and healthy air for all Americans. In view of the environmental and health risks posed by acid rain; the fact that 100 million Americans now live in cities which are out of attainment with public health standards for ozone; and the estimate that current excessive levels of air toxics emissions may result in premature cancer deaths and other serious adverse health effects; it is vital that we move quickly and decisively to reduce these pollutants. The Administration's proposed bill would do just that.

2.) The bill should not impose aggregate costs on the economy that exceed the already considerable costs embodied in the Administration's bill -- with an adjustment of no more than ten percent to reflect certain mobile source provisions added in the House Energy and Commerce Subcommittee on Health and the Environment. The House subcommittee added certain provisions affecting mobile sources to the titles of the bill which relate to non-attainment that will modestly increase the cost of these titles. Unfortunately, several provisions currently contained in the Senate Environment and Public Works Committee's bill -- such as mandatory nationwide second phase tailpipe standards for automobiles, an inflexible second phase of air toxics control, and carbon dioxide emissions standards for mobile sources -- cause the Senate bill to exceed substantially the cost of the Administration bill. The result of an excessively costly bill will be a less competitive American economy with fewer jobs for American workers.

The Administration has received letters from around the country, for example, indicating that a considerable number of plant closings could result from adoption of the Senate's air toxics provisions. The Administration has set up a task force under the chairmanship of the Council of Economic Advisers, and including the Environmental Protection Agency, the Office of Management and Budget, the Department of Energy, and the White House Office of Policy Development, to monitor and estimate the economic cost of various clean air proposals as the debate proceeds.

3.) Controls in the bill should be designed to achieve reductions in the most cost-efficient way -- that is, for the least cost per ton of reduced pollutant. By incorporating flexibility and innovation in its recommended control strategies, the Administration's bill would allow environmental and health standards to be met in a way that creates maximum choice for both states and regulated industries and places fewer burdens on consumers. For example, the Administration's alternative fuels proposal will challenge the automobile and oil industries to produce cleaner vehicles and cleaner fuels at the lowest cost to the consumer.

The "command and control" approach embodied in several provisions of the Environment and Public Works Committee's bill -- such as that which disallows "netting" for factories and commercial facilities seeking to meet ozone non-attainment standards in the most cost-effective way -- results in the same environmental benefit, but at greatly increased cost and with sharply increased impediments to economic growth. Similarly, the provisions in the Environment and Public Works Committee's bill which move up emissions reduction deadlines while failing to provide incentives for clean coal technology needlessly inflate the cost of acid rain control.

4.) The system of emissions trading, which allows acid rain reductions to be achieved in the least costly and most equitable fashion, must be allowed to work. The Administration's proposed acid rain emissions trading program inherently reduces the cost of any given level of sulfur dioxide or nitrogen oxide reduction, and provides an efficient mechanism for balancing the burdens imposed on any given region of the country. The Administration has provided information to several Senators which indicates that this trading system can dramatically reduce the impact of acid rain controls on electric utility rates in any given state, while at the same time reducing the cost of the overall bill by up to billions of dollars per year. In the first phase, the initial allocation of required reductions to 107 plants is essential to ensuring that effective trading opportunities exist. The trading system must survive in a form that achieves environmental benefits comparable to those in the Administration's bill and involves a sufficient number of plants in the first phase to ensure its workability.

5.) The legislation must not include a national electricity tax to pay for controls, which would penalize consumers in those states which have already undertaken reductions by making them in effect "pay twice" for clean air. Supporters of such "cost sharing" argue that it is needed to address regional inequities. Any imbalance in control costs can be addressed far more effectively, efficiently, and equitably through the operation of a robust emissions trading system -- which would not require new taxes.

The Administration took substantial time and effort to craft a balanced proposal. My staff and I stand ready to assist you and the other Members of both the House and Senate as you work to develop legislation which maintains this vitally important balance, and which does not violate one or more of the above mentioned "tests."

I look forward to signing legislation that will accelerate progress toward cleaner air for a growing America at the earliest possible opportunity.

Sincerely,

The Honorable Robert Dole
Republican Leader
United States Senate
Washington, D.C. 20510

Senator Bumpers. Mr. Rosenberg, you ought to be prepared to answer, where that growth is going to take place.

Mr. ROSENBERG. Correct.

The CHAIRMAN. Thank you very much, Mr. Rosenberg.

Next we want to hear from Jim T.B. Tripp, who is counsel for the Environmental Defense Fund in New York.

STATEMENT OF JAMES T.B. TRIPP, GENERAL COUNSEL, ENVIRONMENTAL DEFENSE FUND

Mr. TRIPP. Thank you very much, Senator Johnston.

I am the general counsel for the Environmental Defense Fund in New York. I have also done quite a bit of work in your own good state. I am one of the founders of the Coalition to Restore coastal Louisiana. I have a deep affection for the resources of Louisiana.

The CHAIRMAN. Thank you very much for that.

Senator FORD. Is that in New Orleans or other places?

Mr. TRIPP. Well, its headquarters is in Baton Rouge, but the members of the coalition are from all over the state. And there are two members of the board from outside the state, and I am one of them.

EDF has had a long-term interest in trying to do something about the ravaging effects of acid rain, acid deposition both in the eastern and western parts of the United States. And we are pleased that we now have a bill that the Senate is considering. And we certainly urge the Congress as it deals with the issues that have been raised here to act expeditiously.

I think no better present could be given to this country on the 20th anniversary of Earth Day on April 22, for the Congress to have finished its deliberations and to have passed a strong clean air act, particularly a strong acid rain provision by that date. I would just like to focus on the—briefly on the two major innovative features of S. 1630.

These features were also in general delineated in the administration's bill. One is the cap, and the other is the trading provision. And I will try and show in a minute how they are also related to some degree to the equity cost-sharing issue.

First of all, with respect to the cap, we agree—I agree with Mr. Rosenberg, if we are going to make the effort to reduce emissions sulfur oxides, and particular, and secondarily nitrogen oxides to accomplish a worthy environmental goal, we should set a cap. A cap, in effect, is an analog to a national ambient air quality standard.

We have standards under the Clean Air Act, and those standards are not to be violated for economic growth reasons or for any reasons. They are not met everywhere in the country, but that is the theory of a standard. It is there to protect public health and the environment.

In our view, the cap can also be complied with as well as the reduction scheduled because of all kinds of options available to the electric utility industry. Those options include not only scrubbing, technological control, clean coal fuel switching and so on, but they also include energy efficient investments.

Many states in this country have instituted proceedings by the public state—public utility commissions to encourage investments by utilities in energy efficiency appliances and the like. California is a prime example of that, where our own office, more than 10 years ago developed the ELFIN model to show financially how it was worthwhile from a utilities point of view to facilitate those kinds of investments. NRDC has done that in the northwest; other groups have done it—with it elsewhere.

But there is tremendous opportunity for energy efficiency investments. A recent study that was done co-authored by an energy analyst in our Washington, DC office, looking at the State of New York, a study entitled The Potential for Electricity Conservation in New York shows that it would be cost effective to make energy efficiency investments in that state that could reduce the use of power by more than 30 percent. So that is a real option.

Second, the emissions trading program, a very innovative feature. It is innovative and important in our view, because we should be searching for economic incentive systems that encourage utilities to achieve prescribed goals or standards for SOx reduction in the most economically efficient manner. And the trading system contributes to this end. It adds to the options that plants in both dirtier states and cleaner have to achieve these goals in the national interest.

The options that plants, again, already have include all the technology controls, some fuel switching, clean coal and energy efficiency. But another option available to utilities anywhere in the country, including states that are growing, is to acquire credits. It also provides an incentive for over-control, and in that sense, it provides an incentive for more rapid development, for example, clean coal technologies or more efficient scrubbing systems.

There is an economic incentive under this bill in both phases to go beyond what the phase requirement is, because you do get something of economic value in exchange, namely credits that can be used for growth, can be banked or can be sold. And that adds to the overall efficiency of trying to achieve these important and worthy environmental goals.

For that feature of the bill to work, there is a need for a robust market. And there are certain elements of this bill, including the 2 percent withholding of allowances, which would should encourage a robust market. We would like to see that 2-percent increase to nearer 5 percent. There have been questions raised as to whether or not there would be hording of credits. In general, we do not think that that would be the case, because these credits are valuable assets, and it would be counter to the interest of utilities and rate payers and public utilities commissions to encourage hording. We have more on that subject in the attachment to our testimony.

Finally, on the subject of equity. Equity becomes a greater concern as costs go up. And in that sense, the trading feature of the bill, and the cap together should help assist to resolve the equity questions that all of you have raised this morning. If we can accomplish what we are trying to accomplish here in a way that provides utilities with maximum flexibility, the largest number of options, we should be able to achieve these goals in a least-cost manner. And that will minimize the likelihood of economic disruptions.

And furthermore because of the incentives through the trading system for over-control in states that have high sulfur oxide emissions, there is an equity feature there, which in general is desirable.

So that the basic features—and let me just add once again, energy efficiency. When you think about the equity issues that you have raised, remember that there are incentives here for utilities to make energy efficiency investments, and they should be encouraged because that may be the least-cost way of achieving these goals.

And for those reasons, we support the general features of the President's bill and S. 1630 with a cap, a critical environmental feature, and its innovative economic trading system. Thank you.

[The prepared statement of Mr. Tripp follows:]

ENVIRONMENTAL DEFENSE FUND

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Date: January 24, 1990

BEFORE THE SENATE ENERGY COMMITTEE
IMPLICATIONS OF THE ACID RAIN TITLE OF S.1630
FOR NATIONAL ENERGY POLICY

By: James T.B. Tripp

My name is James T. B. Tripp. I am general counsel of the Environmental Defense Fund, a national, non-profit environmental organization.

This Committee is considering the implications of Title IV of S. 1630 for national energy strategy. S. 1630 contains two rather innovative features: a schedule for reducing regional and national loadings of SO2 followed by a cap on total emissions and an emission trading program. These features are important elements of S.1630, and the primary purpose of my testimony is to explain their function and significance. To understand the implications of these features for energy policy, we should consider how our country has regulated environmental pollution associated with the use of energy by major stationary sources, such as electric utilities, historically.

1. Overall policy - internalizing environmental external costs

A great deal of environmental pollution is associated with the production, transport and use of energy resources. From an environmental perspective, the prices of different forms of energy internalize those environmental costs when standards applicable to all energy sources, stringent enough to protect health and the environment, are in place and properly enforced. The costs of complying with these standards should then be reflected in the prices of energy and, ideally, with these prices fully incorporating the costs of protection of the environment and public health, the market would then sort out consumer preferences for different types and amounts of energy, including electric energy.

For this framework to work, it assumes that standards are both comprehensive i.e., cover all relevant pollutants affecting all environmental media and stringent i.e., compliance means that loadings of the pertinent pollutant individually, cumulatively or synergistically will not adversely affect health or the environment.

Over the last two decades, the Congress has enacted many good laws, including the Clean Air Act, the Clean Water Act, and the SMCRA, to name a few, that have been designed to address pollution associated with major industrial enterprises, including energy production and use. The principal act affecting electric utilities has been the Clean Air Act. In general, as implemented, the Clean Air Act has primarily addressed short-range or local pollution. The Act assumes that pollutants emitted to the atmosphere disperse and, as they disperse, will become less onerous. Standards under this Act consider ambient concentrations in the atmosphere at ground levels. They do not take into account accumulation of these pollutants in soil, water or the entire atmosphere above ground level. Yet, we now recognize that there is a large class of air pollutants that do accumulate and/or are transported long distances and that do their damage as a result of total loadings of those pollutants over periods of many years or decades. Prime examples are the acid rain precursors, SOx and NOx and the greenhouse gases.

As we think about standards and programs to address these, as well as historically regulated, pollutants, we must also search for techniques to minimize the costs of complying with these standards. That is, we want companies to make investments designed to attain standards in the most economically efficienct manner.

2. S. 1630 - The cap

In Title IV, S. 1630 addresses two pollutants, SOx and, secondarily, NOx, that fit into this category that we are describing. Although both are pollutants of health concern, they can do damage to the environment at far lower ambient concentrations because they accumulate in the environment and can be transported throughout the lower atmosphere at great distances. They gravely impair visibility, most noticably in the West, at low ambient concentrations. They cause damage to lakes, estuaries, forests and materials because of impact over long periods.

Given the nature of these pollutants, we are concerned about their total loadings to the atmosphere within regions whose resources can be affected by their transport over a period of many years or decades. Total loadings of SOx and NOx from all major sources within a region impact the environment more than emission rates for very short periods, i.e., hours or days - periods that are, on the other hand, very important in terms of local health impacts.

S. 1630 recognizes these characteristics of SOx and, to a lesser degree, NOx, both acid rain precursors. It prescribes two five-year phases during which, initially, 107 electric power plants and, then subsequently additional utilities emitting SOx above a certain rate and with more than 75 mg capacity, (other sources may opt into the program) must reduce their total loadings of these pollutants. The overall objective is to reduce total loadings, hopefully to a point where their impact on health and the environment will be minimized. From an environmental point of view, it would be desirable to reduce loadings of SOx and NOx even more than S. 1630 mandates.

Further, since it is the total loadings of SOx regionally and nationally that is important, S. 1630 sets a cap on utility emission loadings following the two reduction phases. This is eminently sound environmental and health policy. A loadings cap is the analog of a NAAQS for a pollutant of concern in proximity to a source. Standards for traditional pollutants such as CO, particulates and lead, are not allowed to be contravened to accomodate economic growth. On the contrary, growth should be designed to comply with those standards. Likewise, once we set a standard in terms of total loadings of a regional pollutant such as SOx, we should maintain that standard or loadings cap.

Relaxation of that cap - to accomodate regional economic development or particular economic interest - is counter to the objective of building a sustainable environmental future. In addition, it is unnecessary. Utilities in all parts of the country, including those that are growing the fastest, have numerous options to keep their cumulative SOx loadings below the cap. Under S. 1630, those options include energy efficiency investments and conservation demand management, on the demand side, and, on the supply side, co-generation, fuel switching, scrubbing, clean coal technologies and more efficient boilers. Moreover, under S. 1630, they include another important option - purchase of SO2 emission credits or allowances.

Implementation of these programs will occur largely at the state level where they provide opportunities to assure that delivery of energy occurs at least cost and opportunities to foster energy efficiency investments. Thus, we should consider how implementation at the state level is apt to occur. By taking advantage of these options, we are confident that electric utilities in all parts of the country will be able to provide all of the electric services demanded of them while respecting the cap. In this context, we point out that the cap should encourage electric utilities to give far greater consideration to energy efficiency investments. The work of EDF in California with its ELFIN model, the work of the Natural Resources Defense Council in the Northwest, the on-going efforts of the Counservation Law Foundation of New England with the utilities in New England and other similar actions show that investments by utilities in energy efficiency systems are cost-effective far beyond what utilities are doing today. A recent study The Potential For Electricity Conservation In New York State, by Peter Miller, EDF energy analyst, J.H. Eto and Howard Geller, prepared by The American Council for an Energy-Efficient Economy for the New York State Energy Research and Development Authority, EDC suggests that it makes economic sense for utilities to make energy efficiency investments that could in effect reduce the demand for electric power by more than 30%. There are institutional barriers that prevent utilities from making such investments even where they make economic sense. What is needed is the development of utility financial rate of return systems, as well as competitive bidding procedures, that foster such investments. The New York State Public Service Commission has a major proceeding underway to do this. This should be encouraged.

For now, we point out that an SO2 cap should encourage utility and state PSC policies that foster energy efficiency investments. Such investments, moreover, mean, not only reduced loadings of SO2 and NOx, but all other pollutants, including CO, particulates and CO2, the major gas contributing to global climate change. To provide for this kind of multi-pollutant benefit should be an objective for all environmental laws affecting the production and use of energy.

3. S. 1630 - emissions trading

The second factor of environmental policy that we mentioned above is searching for economic incentives as well as regulatory systems that, in this case, encourage utilities to achieve prescribed reduction goals and to comply with limits on regional loadings on pollutants, such as SOx, in an economically efficient manner. S. 1630 incorporates emissions trading to further this objective. For a discussion of general factors that indicate where trading programs can be used to further environmental goals and that affect the institutional viability of such programs, see J.T.B. Tripp and D.J. Dudek, "Institutional Guidelines for Designing Successful Transferable Rights Programs", 6 Yale J. Reg. 369 (Summer 1989).

Under S. 1630, in Phase I, 107 identified utility plants with capacity over 100 mw and SO2 emisson rates above 2.5 lb. SO2/mBtu must reduce their total tons of SO2 emissions to a specified level equal to the product of their baseline consumption times 2.5 pounds of SO2/mBtu. In the next phase, utility plants must reduce their tons of SO2 emission to a level equal to the product of their baseline consumption times 1.2 lbs SO2/mBtu. Under the emissions trading program, a plant that over controls in a particular phase may receive emission credits. Conversely, one of the options available to a plant to comply with the applicable emission limit is to purchase credits.

With the cap in place, what the emissions trading system does is to introduce more flexibility into the regulatory scheme than would otherwise be the case. Some plants that found it in their interest to do so could over control their emissions. Indeed, they would have an added incentive to do so since they would then earn emission credits or allowances that could be sold or retained to provide offsets for growth. Other plants might prefer for economic reasons to postpone adopting measures to reeduce emissions and to opt instead to acquire credits. Thus, given the limits on total loadings of SO2 that S. 1630 prescribes, the emission trading program enhances the array of options - scrubbing, fuel switching, co-generation or energy efficiency investments - that plants subject to the cap can pursue.

The emissions trading programs will foster economic planning flexibility for utilities only if there is a robust and credible market for SO2 allowances or credits. State public service or utility commissions and some utilities have raised a number of questions about the functioning of the market for credits. One concern expressed is that utilities might hoard credits that they earn or that state PSCs might mandate hoarding so as to assure the utilities in that state the legal right to expand capacity in later years. Since we expect that these credits will have substantial value, we question whether state regulatory agencies would prohibit the sale of those credits by a utility. In any case, we support a modest withholding of allowances by EPA to assure the availability of crdits and to sustain a viable market. The bill allows 2%. We would propose a 5% level in order to accomplish this purpose. In this sense, the emissions trading program supports the integrity of the overall emissions cap since utilities in fast growing states have the option of acquiring credits to offset new SO2 emissions resulting from new or expanded capacity. Attached to this testimony is a more detailed set of questions and responses dealing with the mechanisms of the S. 1630 emission trading program, robustness of the market and modifications to S. 1630 that could strengthen the market.

An emissions trading program for SOx can assist in achieving environmental goals within a region. This is the case since it is the total loadings of SOx from major sources within the region, not the emissions from specific sources, that has environmental consequences. Thus, if emission credits are traded between two utility plants in that region, rates of acid deposition elsewhere in the region may not be affected. In terms of the robustness of the market for credits, the larger the region the better.

On the other hand, in looking at the concept of regional trading, we have to consider whether environmental needs within prescribed regions can be met. If trades occur between utilities that are located in regions that have differing environmental needs, those values may be unduly compromised. More specifically, trading of SOx emission credits between sources in the eastern United States and western United States is likely to result in increases in total SOx loadings in the West to a point that visibility impairment in national parks would be exacerbated beyond current levels. The National Clean Air Coalition opposes provisions that authorize trading between the eastern and western regions of the U.S. for this reason. The environmental needs of the West, in particular, the prevention of visibility impairment in national parks and other high air quality areas cannot be achieved if trading of credits from eastern to western sources is countenanced. For an analysis of the capacity of western utilities to grow to meet western energy needs without east-west trading, see "Acid Rain Pollution and Visibility Degradation in the West: Senate Bill S.1630 Could Provide Protection But It Allows Environmental Degradation Instead", prepared by Robert E. Yuhnke, Environmental Defense Fund (Jan. 17, 1990)

CONCLUSION

The overall structure of S. 1630 with limits on loadings of SOx, allocation of SOx to major sources based on a phased reduction scheme and provision for trading of emission credits is an approach for dealing with pollutants, such as SOx, a primary component of acid deposition, that have broad regional impacts. As such, S. 1630 may serve as a prototype for considering alternative approaches for addressing other energy-related pollutants of regional or global concerns, including the greenhouse gases.

ENVIRONMENTAL DEFENSE FUND

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COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND REGARDING THE MECHANICS OF THE CAP/TRADING SYSTEM AND STATE REGULATORY REVIEW UNDER TITLE IV OF S. 1630

Title IV. of Senate Bill 1630 works toward a 10 million ton reduction of sulfur dioxide from 1980 levels. It does so by ensuring that declines in industrial levels since that date are maintained. It then requires reducing electric utility sulfur dioxide levels to 8.9 million tons by 200. That reduction is accomplished by requiring 107 highly polluting plants to reduce their emissions by 1995 to a level based on a rate of 2.5 lbs/mmBtu and their average fuel consumptions between 1985 and 1988. By 2000, all plants must further reduce emissions to a level based on a rate of 1.2 lbs/mmBtu. Some presently clean plants would be allowed to increase emissions by 20%.

I. REASONS FOR A CAP/TRADING MECHANISM

A cap is necessary primarily to assure that we actually reach and then maintain the 10 million ton reductions of SO2 needed to protect the environment. Absent a tonnage limit, in fact, ICF Resources has estimated that SO2 emissions could increase by almost three million tons by 2005. Without a tonnage limit, the law will lose almost 30% of its intended annual benefit by that date.

A trading system is valuable primarily to reduce the costs of the program. The cost of compliance goes down because some plants can reduce emissions more efficiently than others. If such plants overreduce and sell emissions allowances to others, other plants do not have to reduce as much as required. The economy enjoys a net efficiency gain. ICF Resources has quantified this gain and projected a savings of $4 to $5 billion in 1988 dollars by 2010 compared with a system based on specified emission control with intra-state trading. ICF Resources Inc., "*Preliminary Comparison of Impacts of the EDF* Proposal v. *Alternative Potential Emission Reduction Proposals* Using Comparable Assumptions" (1989).

Less understood, but of equal importance is that a cap and trading each contribute to the effectiveness of the other. Without trading, a cap would not provide a mechanism for responding to future changes in demand. In particular, the cap would not provide any mechanism for new plants to be able to emit even a small quantity of emissions. Because S. 1630 allows new plants to offset their added pollution with reductions from old plants, trading provides for economic adjustment while retaining the integrity of the cap.

Conversely, without a cap, trading would not be environmentally meaningful. Some have suggested that plants could swap their emissions rates. But if those plants have different capacity to produce power and consume fuel, the exchange would not be environmentally neutral. If a small plant traded its high emission rate to a large plant which otherwise had a low emission rate, the result would be much greater emissions.

The only meaningful trades involve trading a volume of emissions. To have a trading sysem, each plant must be assigned a volume of emissions, or in the words of the law, a level of allowances. These allowances collectively add up to a cap.

Finally, a cap/trading system should result in substantial savings of carbon dioxide, which accounts for 50% of global warming. The United States contributes roughly 23% of this CO2, and 30% of these emissions result from utilities. Because a cap and trading will result in increased conservation, increased use of energy efficient cogeneration, and fuel switching to gasses that emit less CO2, this system should have a side benefit of major reductions in CO2.

II. MECHANICS OF TRADING

Under S. 1630 EPA will issue allowances to emit sulfur dioxide with each permit. Each permit will therefore provide annual allowances for five years. The unit of trading will be the right to emit a certain amount of allowances in a given year. Future allowances cannot be used prior to the year in which they apply. If allowances go unused in a given year, however, these allowances are banked and become usable in any future year.

Trading can occur at any time and in any quantity of allowances. The system should operate somewhat like bank accounts that receives a new infusion of cash each year. Each source will have its own account and must hold allowances good in that year as of December 31st at least equal to the source's emissions during the year. At any time, one source can transfer its allowances from its account to another source's account. EPA will immediately register this transfer, so the purchasing utility can be secure of its right to emit. The burden will then be on the selling utility, subject to strict penalities, to reduce its emissions so that at year end its emissions do not exceed its allowances.

Although the bill requires that utilities file compliance plans before the original reductions are required, these plans should not limit flexibility. EPA has authority to reject compliance plans only if they are not feasible-- EPA has no authority to mandate one compliance strategy over another.

This system provides utilities maximum flexibility to respond to market conditions--a flexibility that directly translates into cost savings. The system should also make enforcement easy because the only question for enforcers is whether a source possesses allowances at the end of the year at least equal to its emissions.

The five year permit term limits to five years the trading of allowances that will be immediately registered by EPA. In other words, in 1995, one utility can trade allowances it will receive in 1999 to another utility and EPA will register and enforce this trade. Beyond that time, EPA will not register allowances.

This mechanism, however, does not preclude longer range planning or trading. Utilities will only receive a permit for five years, but the law guaranties them emissions each year indefinitely, subject only to Congress' authority to modify the system as a whole. Even if utilities close down their plants, they will still be able to trade emissions.

This guarantee means that utilities can trade future year allowances indefinitely into the future by contract. Those contracts can be established before the allowances are actually issued. Utilities can even agree to make these contracts enforceable by specific performance. We would also support amendments that would require EPA to register trades in future years allowances beyond the five year permit term.

III. THE ROBUSTNESS OF THE MARKET

Some high growth states have expressed concern that they will not be able to purchase emissions sufficient credits on the market to provide for future electricty growth. We foresee no such problem.

As a preliminary matter, the availability of credits does not produce a technical problem. On the demand side, utilities can satsify future electricity demand by natural gas, by cogeneration, and by energy conservation investments. Even coal burning can occur with emissions well below the present performance standard of 1.2 lbs/mmBtu.

On the supply side, the question is not one of feasibility but of price. At the right price, some utility will have the self-interest to reduce emissions and trade allowances. Indeed, under S. 1630, the cost of producing many allowances is relatively cheap. Utilities presently emitting at high levels of emissions can easily reduce emissions below the 1.2 lbs/mmBtu rate required by 2000 for relatively little additional cost. Between 1995-2000, many utilities can produce credits merely by reducing below 2.5 lbs/mmBtu, which will frequently be cost-effective. With a cap/trading program in place, utilities have a great incentive to keep SO2 reductions low in order to sell credits. Based on supply and demand analysis, we have estimated that emissions credits will be amply available at a cost of $ 400-500 in 1995 rising to a cost of roughtly $750 beyond 2000.

Although some states have expressed concern that state regulators may (or even should) mandate hoarding and disrupt the market, we do not believe they should or ultimately will do so.

First, regulators should not and need not mandate hoarding because all the benefits from a state-imposed retention bank will exist if states do not attempt to mandate hoarding of emissions. Absent hoarding, a robust market will develop that will supply allowances as needed. Because both contributors and purchasers from this market will be national (or at least regional) in scope, both the costs of producing the credits and the costs arising from uncertainty of demand will be smaller. As a result, this national market should prove a cheaper source of credits than the real economic costs of producing a state bank.

Second, regulators ultimately will not mandate hoarding because hoarding will prove expensive to in-state consumers. Utilities will not willingly produce excess emissions allowances unless they are adequately compensated for them. Without compensation, utilities will strongly resist installing additional emissions control equipment that produces an asset (reduced emissions) from which they are not allowed to earn a return. Regulators will have to allow utilities to pass these costs on to consumers if they wish to mandate hoarding. Hoarding will increase electricity rates. On the other hand, if regulators allow utilities to sell these credits out of state, much of the financial gain can be passed on to consumers, lowering rates.

In essence, hoarding will face consumer resistance and will increase the costs on state industry in the near term. These costs sacrifice economic growth today theoretically to provide for economic growth tomorrow that hoarding itself makes less likely to occur.

Even in the long-term, hoarding will increase costs. Because credits available from a state bank will be more expensive than credits purchased nationally, uilities in the future will lose money if they have to purchase credits from a state bank instead of from a national bank. The need for future credits is also highly speculative. Because the acid rain bill itself will provide incentives for new technological improvement, the power plant of tomorrow will have a lower need for emissions allowances. In essence, a regulator mandating hoarding will be engaged in a risky and potentially costly wager about the future market--a level of risk much greater than simply relying on the market itself to make adjustments.

Third, hoarding will not be an effective longterm strategy. Under an emissions trading system, emissions and power are directly related. Even if no federal agency has the mandate to preclude hoarding, the Federal Energy Regulatory Commission still has the power to mandate the interstate sale of electricity. States that have hoarded emissions could therefore find themselves supplying power out of state at a federally established rate. They will face additional localized environmental problems without the benefits.

To provide further guaranties of future credits, S. 1630 has provisions to guarantee credits. Under the bill, EPA will annually hold back 2% of allowances from all sources. Then, in accordance with regulations it will write, EPA will place these allowances on the market at a set price of $1,500 if allowances become unavailable. EPA will distribute revenues to the original allowance holders. This auction assures an annual emissions market of at least 178,000 tons.

An alternative way of assuring a market would be requiring EPA to withhold 5% of each utilities annual allowances. EPA would then auction those holdbacks annually. Utilities wishing to sell futher allowances could contribute to this auction. The proceeds of the auction would be returned to those plants who contributed allowances. If utilities wanted their full allowances, they could simply repurchase the 5% holdback in the auction. In this way, the system would assure a market, and by assuring a market, would defeat any incentive for hoarding.

IV. THE ROLE OF STATE PUBLIC SERVICE COMMISSIONS

We do not support, and S. 1630 does not contemplate, stripping state PSC's of their customary authority both to review major investment proposals and to determine prudency of investments for ratemaking purposes. Apart from introducing new cost/benefit factors, a cap/trading system should not fundamentally alter the present nature of state review. The value of emissions credits should become a new benefit from pollution control investments, and the cost of emissions allowances effectively operate as a new fuel cost.

State regulators should follow market guidance in reviewing utility compliance strategies. They should also develop incentive systems, and incorporate preferences into their prudency reviews, for environmentally preferable investments decisions.

We also recommend that, if regulators disapprove investment or fuel costs designed to produce tradeable emissions credits, they allow utilities to make these expenditures on their own. The additional investment would then not be incorporated into base rate, and additional fuel costs would remain uncompensated. In this way, market forces can help produce emissions without risk to consumers.

Although some regulators have suggested a possible need to require an emissions credit reserve comparable to required reserve power capacity, the comparison is imprecise. Utilities must possess sufficient reserve capacity to respond to highly variable surges in peak load. In comparison to peak load, annual emissions should not vary greatly because they are directly proportional to annual electricity demand, which determines fuel use. Annual electricity demand varies with weather, but not as much as electricity peaks vary. Utilities therefore need not possess substantial allowance reserves to account for annual variation. Any needed end-of-year credits should also be available on the market.

V. INDEPENDENT POWER PRODUCERS

Some independent power producers have expressed concern that credits will be monopolized, or that they will not be able to purchase credits. One solution would simply be to amend S. 1630 to assure that independent power producers may purchase and hold credits.

States should also assist IPP's simply by adjusting their bidding procedures for new power production established following the Public Utilities Regulatory Policy Act. These adjustments should ensure that utilities be required to provide their own emissions credits to IPP's if IPP electricity proposals are otherwise more economical than utility construction. The Federal Energy Regulatory Commission may already have the authority to incorporate emissions allowances into its "PURPA" guidelines and in such a way that these bidding adjustments would be mandatory. We would support legislative amendments that would direct this kind of action by state regulators.

VI. LIMITING EMISSIONS TRADING TO DEFINED GEOGRAPHIC REGIONS

We oppose trading emissions between East and West. Western environments are more sensitive to acid rain emissions than eastern environments, and even a modest increase in emissions would trigger damaging results on its lakes. The West's great parks are also already suffering seriously impaired visibility at present levels of emissions--a visibility problem resulting largely from regional emissions of sulfur dioxide. Accordingly, environmental considerations require no net increase in western emissions. A regional trading system should allow the needed economic flexibility consistent with these environmental needs.

VII. CONSERVATION

The various ratemaking formulas for utilities sometimes create disincentives for least cost business practices of all kinds. Not surprisingly, ratemaking formulas could create disincentives for the creation and sale of emission allowances. Without fundamentally adjusting ratemaking formula, state regulators should at least provide the same incentive to sell allowances as they provide to sell power. They can do so simply by allowing utilities to make the same return on the sale of emissions as they do on the sale of power. Both revenues represent returns on investment.

In addition, as discussed above, state regulators should allow utilities to install control equipment at their own risk to assure that they do not, through error, inhibit sales. In other words, if state regulators do not consider such an investment prudent based on expected emissions sales, they should allow utilities to proceed anyway. In this way, private entrepreneurs can contract with utilities to fund control equipment in return for the right to revenue from the sale of allowances.

We strongly oppose proposals to provide increased emissions allowances for those who make conservation investments. Utilities interested in making conservation investments can opt their otherwise unaffected plants in Phase I into the trading system. If conservation investments generate reduced emissions, they can then bank or sell those emissions credits. The single greatest incentive to conservation flows from preserving the integrity of the cap. In addition, the various proposals to provide additional allowances for conservation that we have seen present insurmountable administrative problems.

We do, however, favor a variety of proposals to encourage conservation and emissions reductions. Most necessary of these are amendments simply to assure that conservation investments receive equal treatment to other forms of investments. We propose, first, to have FERC promulgate non-binding guidelines for ratemaking that would provide rate of return incentives for conservation and for emissions reductions. We would then obligate state regulators to conduct a rulemaking proceeding to consider these rate of return standards. (PURPA compelled comparable ratemaking proceedings for the purpose of at adjusting consumer rates.) State regulators would have no obligation to adopt any particular ratemaking proposals, but they would be obligated to develop a system of their choice that would not penalize these forms of investments. Their ratemaking system would insure that investments in conservation and emissions control provide at least the same overall economic return as investments in new power plant construction.

We believe that this proposal belongs in national legislation because of the benefits that will accrue to all states from the actions of others. Proposals that encourage emissions credits and conservation in other states will help assure an emissions credit market and will provide the host of national benefits provided by conservation.

The CHAIRMAN. Thank you very much, Mr. Tripp.

Next we will hear from Dr. James R. Mahoney, who is Director of the National Acid Precipitation Assessment Program.

Dr. Mahoney.

STATEMENT OF DR. JAMES R. MAHONEY, DIRECTOR, NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

Dr. MAHONEY. Thank you, Mr. Chairman and members of the committee. I appreciate very much your invitation to appear today to give testimony to your committee with the responsibility on energy and natural resources.

The National Acid Precipitation Assessment Program was created by you here in Congress in 1980 to conduct scientific, technological and economic analyses of acidic deposition or acid rain, its causes and effects, and to evaluate the various available approaches for its control.

Your statute assigns to NAPAP the responsibility of reporting its findings for use by the President and his policy officials, by you in the Congress, and by you in the public.

During the first 9 years of NAPAP's mandated 10-year life, its participating agencies have conducted an interagency collaborative program involving about $500 million of sponsored research conducted both by the government agencies and by its contractors and grantees. This is unprecedented in terms of the attempts to develop information on a critical environmental issue.

This research is really unique in the entire world and after some years has finally begun to narrow the previous very divergent views about the effects of acid rain and the various approaches to its control.

In the sense of keeping to a short time, a direct statement to maximize the time for questions, I am going to comment very quickly on the points in my testimony. We want to call attention to our efforts to bring the information developed by this federal program to you and to all of the interested public and, as my statement indicates, there are several ways in which we are doing that even at this time.

One, I presented a statement in the Senate Environment and Public Works Committee hearing last October and, in fact, attached a copy of that statement which was a pretty broad summary of our findings to my statement for today's record.

Similarly, there is a statement that was prepared and I presented at a hearing in the House Committee on Environmental Research in November, and I have incorporated that here as well.

Next a rather unique contribution of NAPAP to get all of our information out with the broadest possible kind of scientific and public review, we began about a year and a half ago the process of preparing extensive state-of-the-science and state-of-the-technology—that is, the control technologies available—review reports. There are 28 of these reports that have been commissioned. Their mandate requires that at each case they cover in their particular area of coverage all of the relevant information available from whatever source in the world, not simply here in the United States.

Almost 300 specialists, technology specialists, economists and scientists and the like have worked on these reports. They are now published as public review drafts and simply as an exhibit of the size—one of the key ones in terms of the status the acidic status of surface waters, lakes and streams I have here in my hand. All 28 of these reports have been published so that they can be critically reviewed and subjected to challenge at a major international conference which we are sponsoring three weeks from now, in fact, that will be attended by scientists and government agency representatives and others from around the world, including very large delegations from here in the United States and Canada among others.

This information and its summaries, given the very large size of it, are available, and we are delighted to provide any of this you would want, both in raw form and by specific commentary as you may be interested.

To mention just one other category of information, we also this last year conducted a survey of research and assessment sponsored by groups other than the federal government. We did this in response to a great deal of interest to have this information drawn together so that we could reference it properly in these major reviews that we have done with the collaboration of several environmental groups and industry organizations and state organizations, state government organizations around the country.

We have concluded a survey of this work, and you may be interested to know that here in the United States more than 800 research projects on acid rain and its effects have been conducted outside of the federal government sponsorship.

The report on that including a breakdown by state and region is literally at the printer now, and we would be delighted to make copies of that available to the committee as soon as we have it back in about 1 more week.

The CHAIRMAN. We would very much like to get that. We appreciate that.

Dr. MAHONEY. Certainly, Mr. Chairman. In fact, we would not send you all of the raw material because the pile would be so large, I do not think you would want to see it all at once. We will send you each a copy of all of the summary material hoping that may be useful and we are ready to respond to more specific requests, of course, for information.

Now, going on to your specific questions, I want to note that NAPAP's job as a technical fact-finder can be preserved only if we stand outside of the policy debate. In other words, we attempt to report information, to get it carefully reviewed, and to avoid the kind of policy debates and interpretive arguments you are hearing otherwise at today's panel.

For that reason we do not have much to add directly to the questions that you posed for this panel. I do want to make a few comments to give you the direction of the work that we have done that is relevant to the three specific questions you have raised, but I wanted to point out that it is an affirmative matter on our part to try to maintain the highest possible credibility for this great bulk of the underlying technology and scientific work that we stand clear of the obvious policy and interpretive issues that you all must discuss and that the President's policy officers, including those here at the table, must discuss as well.

Within that context I note first in the emission cap area we are not doing any kind of universal analysis of that issue. Some of the scenarios which we are evaluating and which will be reported over the next few months do include consideration of both rate approaches and an emission cap approach. Those are not comprehensive cases.

As soon as we have anything, though, which is really all being developed for us by EPA and DOE and its contractors, I am sure that will be made available, and I am sure that EPA will be doing that more generally under Mr. Rosenberg's direction anyway, so we do not have anything substantial new to add in that category.

I think the same kind of comment applies in the allowance trading case. We are currently investigating several of the future outcomes possible. As a result of the kind of legislation and broader set of parameters that we have been considering, all of our analyses that reflect trading assume that the market works perfectly. We know that the issue that you are debating is will it, in fact, work perfectly or will it not, and we know that insofar as the market in any sense—that is, the allowance market—if it did not work perfectly, the result would be higher costs to reach the control levels involved, and so we can cite the obvious, but I just want to make clear for the record that we will not have illuminating specific information on that, and I wanted you to know where we stood.

The third and final category on cost sharing. Again, on the critically important public value issues of who should pay to reach the control levels that we are dealing with, we are not developing analyses on that kind of tradeoff question. We are developing extensive information on the control costs for various levels of control and various positionings of various geographic positionings of control.

This work again, given NAPAP's interagency nature, is being developed by the Department of Energy and by EPA for publication as part of the NAPAP results. Again, insofar as we have that available and as quickly as we have it available, we will provide that to you as well as to the other interested committees here and on the House side.

I think for purposes of time limitation I will leave my direct comments to those that I have just made. I recognize that there are an extremely broad set of questions about the acid rain issue that—some of which you may want to direct to your attention. I am glad to respond verbally now in short form, as you may want to raise questions, and, of course, we are delighted to respond in more detail in written form at a later time.

Thank you again for the opportunity to present the views we have, and we look forward to keeping you up to date on the specific information that we have.

[The prepared statement of Dr. Mahoney follows; attachments A and B appear in Appendix III.]

TESTIMONY OF
JAMES R. MAHONEY
DIRECTOR
NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
JANUARY 24, 1990

Mr. Chairman and Members of the Committee, I appreciate the invitation to appear before you today, to present testimony on the acid rain provisions of Senate Bill 1630, to amend the Clean Air Act.

The National Acid Precipitation Assessment Program (NAPAP) was created by Congress in 1980 (Public Law 96-294) to conduct scientific, technological and economic analyses of acidic deposition causes and effects, and to evaluate the available approaches for its control. The statute assigns NAPAP the responsibility of reporting its findings for use by the President, Congress, and the public. The Federal agencies and departments participating in NAPAP have (1) conducted research, (2) analyzed other technical studies conducted in the United States and around the world, and (3) established an assessment framework to report technical information in a manner useful to policy officials and public.

To preserve its credibility as a fact finder, NAPAP does not make recommendations about specific control levels. We recognize that you in the Congress, together with the President and his policy officials must make these decisions after considering the available scientific information from NAPAP and elsewhere, and weighing many other concerns.

My testimony today responds to your request for comments on the acid rain provisions of S. 1630, and to three questions regarding the energy policy considerations relating to: (1) the emissions cap, (2) the allowance system; and 3) cost sharing. I will first describe NAPAP's recent and ongoing reports relevant to your request, and then comment on some of the acid rain provisions of S.1630 not covered in NAPAP's other reports, including:

- Inter-pollutant trading (Section 403(c))
- Future reporting requirements (Section 404)
- National Acid Lakes Registry (Section 405)
- The continuation of NAPAP and future research and assessment needs (Section 408)

In October, 1989 I testified before the Subcommittee on Environmental Protection of the Committee on Environment and Public Works. In that statement, a copy of which is attached for your reference and which I request be included in the written record, much of the current scientific information on acidic deposition effects is summarized (Attachment A). In November, 1989 I testified before the House Committee on Science, Space and Technology, Subcommittee on Natural Resources, Agriculture Research and Environment. In that statement, a copy of which is attached and which I also request be included as part of the written record, I presented my views on the research and development needs related to air pollution problems, particularly in light of pending proposals to amend the Clean Air Act (Attachment B). These statements summarize NAPAP's current perspectives, pending completion of several major reports which I describe below.

NAPAP will complete its ten-year mandate in 1990 with the publication and public review of a comprehensive Integrated Assessment on the causes and effects of acidic deposition, combined with comparative analyses of the costs and effectiveness of various emission reduction strategies. NAPAP's twenty-eight State-of-Science and State-of-Technology Reports (SOS/T) which are currently available as public review drafts, and its Integrated Assessment to be published by September 1990, will provide extensive documentation and recommendations on the major scientific and technological issues related to acidic deposition.

NAPAP's SOS/T reports will be critically reviewed at a major international conference during the week of February 12, 1990 in Hilton Head, South Carolina. Copies of the public review drafts of the SOS/T reports are presently being shipped to over 500 conference registrants representing approximately thirty-five nations.

Another relevant source of information will be NAPAP's Findings Update. This document will summarize principal new technical information which has become available in 1988 and 1989. We plan to have this document available for distribution by the time of the NAPAP International Conference.

NAPAP also has recently compiled a survey of nonfederal-sponsored acid rain research. This effort was requested by State and nongovernment groups and was conducted in close cooperation with state governments, the private sector and various environmental organizations. It documents over eight hundred research project descriptions. A draft copy of the document was distributed to the NAPAP SOS/T authors for review and use in July, 1989; the final document will be published in February and distributed at the International Conference.

Now, I turn my attention to relevant provisions of S.1630 not addressed in other NAPAP testimony.

Inter-Pollutant Trading.

Section 403(c) would allow for reductions in NO_x to be substituted for SO_2 reductions in the ratio of 1.5 $NO_x = 1.0\ SO_2$. We can proportion the acidity of SO_x to NO_x, but we know far less about the behavior of nitrogen in ecosystems, compared to that of sulfur. We do know that the role of nitrogen is far more complex. In addition to acidic deposition, the oxides of nitrogen play a key role in lower tropospheric ozone formation. Although the majority of NAPAP's research has focused on acidification effects caused by sulfur emissions, there are several important findings related to the role of nitrogen. Until several years ago, it had been thought that nitrogen oxide emissions were relatively unimportant for aquatic acidification. It was assumed that ecosystems susceptible to acidification were in general 'nitrogen starved", and that any atmospheric input of nitrogen would be utilized within the terrestrial environment and hence not find its way into surface waters. Later it was recognized that at certain times of the year when the temperature is low (and hence terrestrial bio-chemical processes are proceeding more slowly) peaks of nitrate concentrations are found in surface waters, and that these peaks are often associated with episodes of increased acidity.

Based on available information, some streams and lakes in the Northeast and parts of the Mid-Atlantic regions experience episodes of adverse water chemistry that have the potential to be biologically deleterious. Within these regions, nitrate seems to have the greatest influence on episodes, since it is the anion most frequently associated with episodes initiated by spring snowmelt. Evidence is also accumulating that nitrate concentrations in general are increasing in acidic lakes in the Northeast (not only at times of episodes) and these may well be contributing to the fact that some lakes continue to acidify, despite significant reductions in sulfate.

Nitrogen fertilization from atmospheric deposition also has been suggested as a factor in high elevation forest decline, where excess nitrogen has been hypothesized to impact the frost hardiness of trees. Although nitrogen saturation may be occurring at some locations, research results to date have apparently not supported this hypothesis. Atmospheric nitrogen deposition also has been implicated as a factor in the eutrophication of estuaries such as the Chesapeake Bay.

Since NO_x is one of the primary factors in ozone formation, reductions in NO_x may reduce the peak regional ozone concentration, but may actually lead to increases in total regional exposure to ozone. At ambient levels, ozone is recognized to be the primary source of atmospheric pollution damage to forests and agricultural crops. There are, however, some benefits associated with nitrogen deposition, such as the nitrogen fertilization of crops and unmanaged forests and grasslands.

Exceedances of the National Ambient Air Quality Standard (NAAQS) for ozone occur in many parts of the United States, and reduced lung function in sensitive individuals may result from ozone exposure in these areas. In summary, reductions of NO_x would probably produce ecosystem benefits in areas where soils are currently nitrogen saturated and, in cases for which NO_x emission reductions result in ambient ozone reductions, there would be significant benefits to human health and crop and tree productivity.

Future Reporting Requirements.

Section 404 (Acid Deposition Standards) would require a report, thirty-six months following enactment, on the feasibility and effectiveness of an acid deposition standard (or standards) to protect sensitive aquatic and terrestrial ecosystems.

I support additional analyses to assess the potential efficacy of new requirements for SO_2 and NO_x emissions reductions. Such analyses should be undertaken in a manner allowing ecosystem recovery to be evaluated as it occurs.

The types of research and monitoring activities that would make it possible to assess the full consequences of the Bill are discussed below in the context of post-NAPAP activities. The desirability of analyses such as those called for in Section 404 of S.1630 should be evaluated relative to other research and monitoring activities, such as those already funded in the Environmental Monitoring and Assessment Program (EMAP) at EPA.

National Acid Lakes Registry.
Section 405 calls for the establishment of a National Acid Lakes Registry. This is an excellent idea in principle, but in practice it is not possible to sample all lakes. A more practical approach is a statistically valid sampling of lakes, adequate for regional extrapolation.

This sort of monitoring, which might also be expanded to include stream and biological monitoring as well as lakes, would contribute critical information for future control strategy evaluations.

The Continuation of Research Intiated Under NAPAP.

I believe the type of interagency research coordination fostered by NAPAP has been beneficial and much of it should continue. In addition, I believe a great deal of the type of research initiated by NAPAP needs to continue to evaluate the impact of any acidic deposition controls. Several types of studies that merit careful review and consideration for the post-1990 period are noted here. These studies can be accomplished through a variety of organizational arrangements, including several programs already underway at several of the NAPAP participating agencies.

1. Trend Monitoring. Standardized monitoring programs (augmented by a research effort), conducted at representative locations on a continuing basis, provide the best "ground truth" allowing us to monitor the changes in emission levels, air quality, deposition levels, and soil and ecosystem changes resulting from enactment of the Bill. The long term trend information also is useful to assess and improve the scientific models developed under NAPAP and elsewhere for emissions, deposition and ecosystem changes.

2. Long-term Effect Studies. In addition to monitoring future trends, it would be desirable to continue several key studies that address long-term multiple-stress processes and their cumulative effects. For example, long-term studies are needed to better understand the effects of multiple pollutants on forest productivity. These studies would contribute to our knowledge of the need for additional pollutant controls.

3. Other Specialized Studies. The NAPAP Assessment uses approximately forty different process and effects models, in many cases developed or improved through NAPAP research. Improvements and further validation

of these models can help reduce key uncertainties and lead to better understanding in such areas as aquatic effects, health effects, and the impacts of acidic deposition on exposed materials in communities.

4. Continued Development and Demonstration of Mitigation and Control Measures. Because of the long time period for development and demonstration of advanced combustion and control technologies and the potential improvements such technologies can bring, appropriate technology development should continue to be supported. For example, current DOE-sponsored development of NO_x controls and combined SO_2/NO_x controls for stationary combustion sources should be continued, in addition to the emissions reduction technologies being demonstrated in the Clean Coal Technology Program. Moreover, energy conservation, renewable energy technologies, alternative fuels development and other measures improving the overall cost-effectiveness of controls should be encouraged.

5. Continuation of Assessment Activities. NAPAP has developed an approach that provides a useful foundation for the assessment of emerging natural resource and environmental issues.

   The NAPAP approach includes:

   - A formal assessment plan, indicating how research information will be used to answer specific questions important for policy evaluation.
   - Public review of the assessment plan by all interested individuals and groups.
   - Documentation of the models and data bases used in the assessment.
   - Comparative evaluations of alternative future scenarios.
   - Explicit treatment and reporting of uncertainty in assessment findings and projections.
   - Extensive peer review of all analyses, including independent scientific commentary on the entire assessment approach.

Future evaluations and assessments of regional scale air pollution issues should include considerations of controls for regional ozone and greenhouse gases, in addition to acidic deposition precursor pollutants. We now recognize that evaluations of global change, regional ozone levels, and acidic deposition issues have overlapping research, monitoring and evaluation needs. EPA's EMAP program and related studies in other agencies incorporate recognition of these overlaps.

6. Collaboration Among Federal Agencies and Among Federal, State and Nongovernment Sponsors of Research and Assessment. NAPAP has demonstrated significant benefits resulting from federal interagency sponsorship, review, and reporting of acidic deposition studies. The result has been an efficient use of federal research funds and multiple agency reviews of research plans. Also, NAPAP interactions with the states and other nongovernment sponsors of acidic deposition research indicates the benefits of a focal point for information and cooperation. To promote continued efficiency in research budgeting and to foster wide review, collaboration among federal agencies, state governments and others should be pursued.

In the final part of my testimony I comment on the three questions posed in your invitation letter. These questions largely deal with policy issues that are outside of NAPAP's scope of analysis. Therefore my comments are limited to those technical aspects that NAPAP is evaluating.

Emissions Cap vs. Rate.

One principal difference between the requirements of S.1630 and a straightforward 1.2 lb SO_2/MMBtu emission rate limit proposed by others is the potential for growth in emissions. Under the provisions of S.1630, almost no increases in emissions from existing or new plants would occur, since: (1) the bill would require emissions from all new power plant units to be offset by reductions from existing units, and (2) existing 'affected' units would be subject to emission allowances based on historical capacity factors.[1] These two limits of growth would not be in effect if the only requirement were a reduction of each unit's emission rate to 1.2 lb/MMBtu.

NAPAP is planning to evaluate a few example scenarios for both rate based limits and emission caps as part of its Integrated Assessment, as reported in its August 1989 Assessment Plan Update. None of these comparative analyses is currently available; therefore we cannot currently comment on the differences expected.

Allowance Trading.

NAPAP's assessment does not include an evaluation of how effectively the market-based approach to emission trading operates. NAPAP's analyses of emission reductions expected under various allowance approaches assume that the market for allowances operates perfectly. Insofar as the market operates imperfectly, larger emissions reductions and higher costs will result.

Cost Sharing.

NAPAP has not evaluated the consequences of alternative ways of financing acid rain controls. Although we will report cost information for various control scenarios in our final assessment, we feel that alternative financing decisions are the domain of public policy officials, rather than NAPAP.

Mr. Chairman and members of the Committee, I would be pleased to respond to specific questions you may have. Thank you again for this opportunity to present the information available from NAPAP for your consideration.

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[1] The only growth in emissions after 1985 would come from small units under 75 MW and new units that come on line between 1985 and enactment.

The CHAIRMAN. Thank you very much, Dr. Mahoney.

Next we will hear from A. Joseph Dowd, who is Senior Vice President and General Counsel of American Electric Power in Columbus, Ohio.

STATEMENT OF A. JOSEPH DOWD, SENIOR VICE PRESIDENT AND GENERAL COUNSEL, AMERICAN ELECTRIC POWER SERVICE CORP.

Mr. DOWD. Well, thank you, Mr. Chairman.

I would like to begin by thanking you and this committee for insisting that the energy implications of pending acid rain legislation be fully explored.

I might also mention that I am here representing the American electric power industry, not the electric utility industry or not the Edison Electric Institute, and so you should please bear that in mind.

First, a couple of words about AEP. We provide electricity throughout much of the nation's industrial heartland. Because we are big and because we burn a considerable amount of local high sulphur coal, our customers would be very hard hit by the acid rain provisions of S. 1630.

Many of these customers are large, energy-intensive, economically marginal industries such as aluminum, steel, glass, chemicals and autos which would suffer rate increases on the order of 24 percent. Our two largest customers, two aluminum smelters, would experience rate increases approaching 40 percent.

Now, in my file testimony I have addressed in some detail the issues of emissions trading, the emissions cap and cost sharing. Suffice it to say here that we favor emissions trading per se, but we fear that it will be greatly inhibited by the cap because of the cap, we will, in fact, be trading in that most precious of commodities, regional economic growth.

The CHAIRMAN. Mr. Dowd, a question of the operation of the cap and of the trading will be one of the central questions here, so you and I know Commissioner Badger is interested in that. You might explain at this point if you would like to, and we will invite Commissioner Badger to do the same, your view of how the cap and the trading system works because I think there will be, perhaps, some difference of opinion as to how it will work.

Mr. DOWD. Well, as I say, our concern is that with the cap, the emission allowances, at least for a very long period of time, perhaps decades, will be extremely scarce and, therefore, extremely valuable, and that these excess emissions allowances, in fact, represent regional economic growth.

Now, our concern is that trading may be inhibited by that fact because you are imposing upon a very highly regulated industry. You are attempting to impose upon it a concept of free market trading in a very essential and scarce commodity here.

Now, we are subject, as I say, to regulation, and it seems to me that it is the very essence of state regulation to ensure that there is an adequate and reliable supply of electricity to support future population growth and future economic growth within a state.

Therefore, we foresee at least the possibility that state commissions will inevitably exercise a high degree of oversight with respect to emissions trading in some instance there may be no problem. In other instances where they foresee economic growth on the horizon, it is very likely that they will insist that a portion or perhaps all of those emissions credits be reserved for future economic growth within that particular state. I think this is really the substance of our concern with respect to emissions trading.

Now, as I say, again, the problem is in large part created not by the trading, per se, but by the existence of the cap, and that cap is apparently sacrosanct because it is sacrosanct, Washington's brightest minds have been very busy trying to devise innovative mechanisms to make emissions trading under the cap work, but these mechanisms only succeed in making the legislation more onerous and more complex and in moving it further away from free market trading and in the direction of command and control.

Now, the tenacity with which the proponents of the legislation are dug in on the cap on the 10 million ton reduction and the phase II deadline, this tenacity tends to take on an unreal quality in light of recent disclosures by NAPAP that indicate that the environmental benefits to support this costly legislation simply are not there.

Now, Dr. Mahoney in a briefing memo dated April 26th of last year stated, and I quote, "The only benefits generally agreed to be expected from new acid rain control will be improvements in acidic and sensitive lakes and streams. There is no consensus that improvements in other effects categories would be as significant. Possible health risk associated with acid rain pollutants, acid aerosols are currently being evaluated. Improvements in degradation of exposed materials and an atmospheric visibility would occur but may not be large. There is no evidence of widespread forest damage from acid rain with the possible exception of mountaintop exposure to acidic clouds."

He also pointed out that, "Ozone can cause forest damage in some regions but that SO_2 controls will not improve such ozone damage."

Now the acidification of northeastern lakes has always been the principal focus of the acid rain concern, and indeed its driving force. But we now learn from NAPAP that with or without acid rain legislation there will be no deterioration in those lakes over the next 50 years.

Furthermore, we are told that an SO_2 reduction in the range of 10 million tons would, over the next half century, restore only 75 acidic northeastern lakes.

Now, using EPA's projected cost for H.R. 3030, the House bill, this equates to $53 million per lake per year.

Now the irony of all of this is heightened by the fact that much of this, the primary environmental benefit mind you, could be obtained more quickly, and at an infinitesimal fraction of the cost through lake liming.

Mr. Chairman, someone has to ask the question, is the restoration of 75 lakes by the year 2040 worth the shutdown of 11 percent of our Nation's remaining aluminum production capacity and the consequent loss of 2,300 jobs? Is it worth the loss of perhaps tens of thousands of United Mine Workers'jobs? Is it worth plant closings and job losses in other industries? Is it worth rate shock throughout the Midwest?

A preliminary EPRI report, the Electric Power Research Institute, appended to my testimony, states that a vigorous clean coal technologies program can achieve essentially the same environmental benefits at an overall cost to society of at least $120 billion less.

Using EPA Administrator Reilly's own figures, an 8-million-ton bill would cost the nation a whopping 42 percent less than a 10-million-ton bill.

Now would someone please tell the Congress what the resulting loss of environmental benefits would be if we went from a 10 to an 8-million-ton bill?

Our reading of NAPAP indicates that you could not see the difference.

Now in view of the paucity of environmental benefits emerging from the NAPAP studies, it is not too late for the Congress to step back and to take another look at this legislation, which has the potential for crippling the economy of the Midwest.

Defer action until NAPAP's integrated assessment, with its various cost/benefit analyses, is available to the Congress late this summer.

If Congress feels it must act right now without that critical information, why then, in view of the meager resulting environmental benefits, why must it be such a harsh bill? Why cannot it be a more moderate bill, for example eight million tons, no cap, and/or an extended Phase II compliance date to give the clean coal technology some breathing room in which to grow?

We now know that the environmental benefits are going to be very slim in any event.

Mr. Chairman, thank you.

[The prepared statement of Mr. Dowd follows:]

Testimony
of
A. Joseph Dowd
Senior Vice President and General Counsel
American Electric Power Service Corporation

Before the
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

on

PENDING ACID RAIN CONTROL LEGISLATION

January 24, 1990

Mr. Chairman, Committee members, my name is A. Joseph Dowd. I am Senior Vice President and General Counsel of American Electric Power Service Corporation (AEP). I appreciate the opportunity to appear here today on behalf of the American Electric Power System (AEP). Also, we very much appreciate the fact that you are holding these hearings in order to explore the energy implications of one of the most far reaching and costly pieces of legislation ever to come before the Congress.

AEP is one of the largest coal burning electric utility systems in the United States. Typically we burn more than 40 million tons of coal per year -- much of it of the high sulfur variety that is indigenous to our service area. We have more than 20,000 megawatts of coal-fired generation in operation, with an additional 400 MW scheduled for operation this year and next year. We have extensive experience burning low as well as high sulfur coal. We have two scrubbers in operation on our system with a third under construction. We are at the very cutting edge of the innovative clean coal technologies effort by virtue of a $780 million program to pioneer the pressurized fluidized bed combustion concept. We have state of the art coal cleaning plants to wash much of the coal that we mine ourselves.
Our power plants are among the most efficient in the nation, which means that we are able to squeeze a greater number of kilowatt hours of electricity out of a given amount of coal. This generating efficiency goes virtually unnoticed by those crafting our environmental laws, but it is one of the most

sensible, cost-effective methods of pollution control available, with little down side.

To achieve another kind of efficiency -- the efficiency of scale -- the AEP System has a history of building very large power plants. That is one of the reasons why, on any given list of big SO_2 emitters, AEP plants will appear prominently (just as they do on any list of the most efficient plants). For example, we could have built four 650 MW plants instead of the 2,600-MW Gavin Plant. Those four plants in the aggregate would have emitted at least as much SO_2 as Gavin, but would not have appeared on anyone's list of the top emitters. We, of course, concentrated the generation in one power plant in order to achieve those economies of scale.

One final point before addressing the legislation. The AEP System has operated in compliance with all applicable air pollution control laws and regulations at a cost of approximately $1.5 billion to our customers. This is no mean feat for a large, predominantly high sulfur coal-burning system operating 44 coal-fired generating units and which has the additional responsibility of obtaining fuel and providing engineering support for the eleven OVEC (Ohio Valley Electric Corp.) units as well as two units owned by Buckeye Power, Inc. This record is all the more remarkable since it has been accomplished during a period of rapidly changing environmental requirements and in the context of an extremely litigious society.

While maintaining this record of environmental compliance, we have, at the same time, been able to provide electricity to our customers -- particularly our heavy industrial users -- at rates that assisted them to sustain operations during the recession of the early 80's and have helped them to recover and maintain their viability in today's world economy. It has been a difficult tightrope walk for us. We believe that we have walked it successfully. But we also regretfully believe, assuming the enactment of S. 1630 or H.R. 3030, that the era of Midwestern economic competitiveness may soon draw to a close.

I would like now to turn to the subject matter of this hearing and provide the Committee with our views on S. 1630 and the Administration's bill, H.R. 3030. In compliance with the Chairman's request, my remarks will cover, among other things, the controversial issues of emissions trading, the emissions cap and cost sharing.

First with respect to emissions trading. Emissions trading is a positive aspect of this legislation and AEP favors it. It doesn't take a Nobel laureate in economics to understand that to the extent that emissions trading takes place, compliance costs can go in only one direction -- down. Trading is just plain common sense. In our analyses of previous acid rain bills introduced during the decade of the 80's, we always assumed that emissions trading would be permitted -- at least among the companies of multi-state utility systems such as AEP. Not to allow trading would be completely irrational. So, as you can see, AEP supports the concept of emissions trading.

Our concern, however, is that under these bills much less inter-utility emissions trading will take place than is projected by U.S. EPA. Moreover, such trades as may occur will not reflect the ease of checking account transfers as has been suggested by U.S. EPA. And, to the extent that such trades do not occur, the cost of the legislation will inevitably be higher -- perhaps much higher.

Why are we bearish regarding the amount of emissions trading that will take place?

We believe that a number of fundamental problems exist which are, at bottom, created by the absolute emissions cap, i.e., by the requirement in the legislation that all power plants which go into service after the enactment of the law must have their SO_2 emissions offset 100% by further reductions at the finite universe of existing plants -- all of which existing plants will be emitting at very low levels after 2000.

While the cap will have the effect of enhancing the value of the emissions allowances, it will also, we believe, result in a partial paralysis of the emissions trading process. This partial paralysis will stem from the interaction of two basic factors. First, the legislation attempts to impose a free market-based trading program upon one of the most heavily regulated industries in the United States. This might not be a problem if we were trading in widgets. But we are not (and this is the second basic factor). When we trade emissions allowances, what we are in fact trading is nothing less than regional economic growth. And what could be more impressed with a public interest than regional economic growth! The local, state and regional political-regulatory communities inevitably will have a major voice in deciding how many of these precious allowances should be traded away and how many should be reserved or banked ("hoarded" is the now popular term) to provide for the future economic growth of the region that generated those allowances. This, of course, is the very essence of state utility regulation, i.e., to ensure an adequate supply of electricity in the future in order to take care of population and economic growth within the state. But such state regulatory oversight can only have a numbing effect on emissions trading and, thereby, will increase compliance costs above that projected by U.S. EPA. The corollary of such state regulatory oversight is that utility allowance sellers will enter into trades with utmost caution. This, too, will decrease trading volume and increase compliance costs.

It is the emissions cap, i.e., the 100% offset requirement for new plants, that gives rise to virtually all of the problems related to inter-utility emissions trading, e.g., concerns in Florida and the Southwest regarding limitations on economic growth, IPP concerns regarding possible anticompetitive effects, concerns regarding "hoarding", concerns that future facilities will rely almost exclusively on natural gas in order to avoid the 100% offset requirement to the great detriment of our nation's most abundant energy resource: coal, etc. Eliminate the new unit cap and all of these intractable problems disappear. The nation's future power plants could then be built by the utilities, the IPP's and the QF's as and where needed to provide for the nation's economic growth -- and they would be built subject to the most stringent emissions controls that ever-improving technology can devise.

Elimination of the new unit cap is the obvious, direct and sensible way of dealing with these many problems. But, we are told that the cap is sacrosanct, inviolable. We are told that we must live with the cap no matter what. And so the energies of congressional and agency staff have been diverted into an effort to make the best of a bad situation, thrashing about to develop "innovative" mechanisms to make inter-utility emissions trading under the cap work. But all that these mechanisms succeed in doing is to make a very complicated and costly bill even more complex and costly.

Thus we are all busy studying numerous proposed mechanisms to compel overcontrol in order to generate excess allowances, to confiscate allowances, to set a statutory price for allowances, to induce utilities to sacrifice allowances in exchange for a subsidy, to force an artificial depreciation of the value of allowances, to inhibit state PSC oversight, etc. All this sounds very much like "command and control" and is a far cry from the free market trading in emissions allowances that was the centerpiece of the President's proposal. And all because of the emissions cap.

S. 1630 incorporates one such mechanism (pp.453-45 of printed bill) which requires the utilities to turn over to EPA 2% of their Phase I and Phase II allowances, thereby compelling them to reduce their emissions even further. This forced "overcontrol" is designed to generate additional allowances which

EPA would then capture and try to sell to qualified purchasers at the questionable, inflexible and statutorily-set price of $1,500 per ton. Of course, this mechanism makes the bill even more costly and more onerous.

Also, there exists considerable controversy regarding what the level of emissions were in 1980. This controversy centers around the amount of industrial emissions in that year. Were there only 1 million tons as EPA claims or 2.7 million tons as the electric utility industry claims? This controversy is critical only because of the existence of the emissions cap. Eliminate the cap and the issue becomes moot.

There is one other aspect of the cap of which this Committee should be made aware. The cap compels the use of arbitrarily selected baseline years (1985-87) in determining the unit-by-unit caps which make up the nationwide cap. Using AEP as an illustration, during those base years the economy of our service territory was beginning to recover from the recession of the early 80's which had hit our region of the country very hard. As a result, the capacity factor of AEP's affected coal-fired units during those years averaged only 56%. This means that under this legislation the largest electric power supply system in America's industrial heartland could not in the future operate the great bulk of its generation at any higher than 56% of capacity unless it could create or purchase excess allowances to support an increase in that capacity factor. The effect of this is to increase significantly the cost of compliance. It is as if an automobile factory with the capability of producing 1,000 cars per year was directed by the government to limit its production to 560 cars per year in the future. We submit that on its face this does not make good economic or energy sense.

This is but one example of the gross inequities that will be scattered at random throughout the country as a result of the necessarily arbitrary selection of a base period (which is needed to compute the emissions cap). Another example involves utilities which placed base load nuclear capacity into service during the baseline period and backed off their coal-fired plants with the intention of bringing them back gradually as demand increased in the future. Under these bills, such utilities will be stuck indefinitely with absurdly low, atypical capacity factors. This is regulation by "the roll of the dice". There are many such horror stories. Bear in mind that they all arise from the imposition of the cap. Eliminate the cap and they are gone.

I understand that the Administration is aware of the inequity of selecting an arbitrary base year period and is considering an amendment that would give the utilities the choice of two other three-consecutive-year base periods so long as each includes the year 1985. While such an amendment should afford some relief, it would not take care of AEP's problem. All three of those baseline periods would provide us with essentially the same low capacity factor -- and we do not believe that we are atypical in this respect.

The final problem is basically procedural, i.e., a great deal of bureaucratic red tape inheres in the permit program which is unnecessarily superimposed upon the allowance system. The most obvious solution is to sever the permit program from emissions trading -- and this is precisely what Congressman Dingell has done in his recent legislative proposal. Related to this is the fact that under the pending bills, each and every affected unit in the United States has its own permit incorporating its own emissions cap. We would urge the Congress to consider substituting a utility system-wide cap for the unit-by-unit caps. We have some concern regarding the possible loss of operational flexibility -- particularly during the latter part of each year -- under the unit-by-unit approach since each affected unit (not each utility or system) would have its own individual annual target to achieve. We need to be able to operate our system as a system -- not as 44 individual generating units. However, the statutory language is unclear on this point -- particularly in H.R. 3030. We, therefore, urge that it be clarified to leave no doubt that penalties will not be imposed so long as the annual system emissions cap is not being exceeded. The goals of the legislation will not be compromised by replacing the unit-by-unit cap with a system-wide cap. Environmentally, absolutely nothing is sacrificed and the potential for utility operational flexibility is gained. We urge that favorable consideration be given to this innocuous amendment.

Cost-sharing is probably the most contentious aspect of this legislation. It seems as if there are an infinite number of ways of looking at the equities of cost-sharing. One might logically assume that AEP, as a large, coal-burning Midwestern utility would favor cost-sharing. And we might if we thought there was a chance of obtaining true cost-sharing, i.e., a non-graduated tax on generation. But that doesn't seem to be in the cards. Mr. Dingell's emissions fee proposal really does not help. The burden of the emissions fee falls most heavily upon those it is designed to assist. And the proposal is made less attractive because utilities that avail themselves of the subsidy must surrender without compensation a large part of their Phase I emissions allowances.

There is a concept currently under consideration which, in our view, may have the effect of ameliorating somewhat the harsh impact of the Phase I requirements upon the Midwest. It is called the 2-for-1, i.e., for each ton of overcontrol achieved through scrubbing during Phase I (1996-2000), the utility would receive credit for two tons. The principal virtue of the 2-for-1 concept is that it clearly does not involve a tax and, therefore, should not meet opposition on that ground from the Administration or the western states. The principal concern voiced by environmentalists is that the bonus tons created by the 2-for-1 may prevent the achievement of the 10 million-ton reduction by the Phase II compliance deadline. However, it should be borne in mind that the bonus tons are temporary in nature (they could not be created beyond the year 2000) and would eventually be used up. In fact, to the extent that the bonus tons are permitted to be applied to the achievement of the Phase I requirements, the achievement of the 10 million-ton reduction by the Phase II deadline would not be compromised. In any event, any tonnage shortfall beyond 2000 would, in all probability, not only be de minimus, but short-lived, as well. It is hard to characterize the 2-for-1 as cost-sharing. That, in fact, may be its real principal virtue.

AEP has not to date advocated cost-sharing under S. 1630 or H.R. 3030. Rather we would prefer a more moderate, a more balanced bill without cost-sharing, as discussed below. However, should the Senate revert to a 20-plant control program in Phase I (which we understand is also under consideration), then real, non-cosmetic cost-sharing, i.e., a non-graduated tax on generation, would become absolutely essential. To impose the entire Phase I reduction burden on the customers of only 14 or 15 utilities without some form of true cost-sharing would be so grossly unconscionable as to verge on being cruel. Such a program would be in the nature of a major national environmental experiment which clearly would justify national funding. We would hope that any consideration of a 20-plant approach would recognize true cost-sharing as an absolute imperative. However, as stated, we have not advocated cost-sharing with respect to S. 1630 or H.R. 3030 as they are presently written. Rather, we would greatly prefer that these bills be moderated. The remainder of my testimony will address the nature of and the justification for such moderation.

Our most basic concern is that S. 1630 and H.R. 3030 are single-purpose bills, i.e., their purpose is to reduce emissions to a very low level and to keep them there forever. Looked at solely from an environmental perspective, this is a commendable purpose. However, it cannot be looked at solely in that light. There are broader considerations. This legislation would affect the rate of economic growth and regional patterns of economic development throughout the nation for decades to come. Some regions may prosper while others may wither. It will, by indirection, dictate national energy policy far into the future. For example, if SO_2 emissions offsets prove to be as scarce after the year 2000 as we believe, power supply developers will embrace natural gas in order to avoid the problem and, as a consequence, our nation will have turned away from what is by far its most abundant energy resource: coal. While this may be good for the gas industry in the short term, we submit that it is not good national energy policy.

Economic policy and energy policy are every bit as vital to the well-being of the American public as is environmental policy. Yet it is difficult to discern any balance, any semblance of trade-off in these bills. Their environmental draftsmen seem to have carried the day. If either is enacted in its present form, economic policy and energy policy will have been determined and the nation will have no choice but to adapt to it. It is unfortunate in the extreme that the nation's national energy policy had not been developed and put in place first so that these bills, with their narrower focus, could be considered by the Congress against the backdrop of an established energy policy.

We also respectfully urge that these bills be reevaluated in the light of recent disclosures by NAPAP. As a result of Dr.

Mahoney's testimony before the Senate Subcommittee on Environmental Protection on October 5, 1989 (and the interesting colloquy between Dr. Mahoney and Senator Moynihan -- the father of NAPAP -- during that hearing (Tr.pp.39-47)), an awareness is building that the environmental benefits necessary to justify this costly legislation simply are not there. It is true that Dr. Mahoney stated at the outset of his October 5 testimony that in his view

> "...emission reduction in this range [10 million tons] would benefit aquatic resources and would mitigate other environmental effects caused by acidic deposition and its precursor gasses."(Tr.p.13)

But this is simply a truism. Less emissions are, of course, better than more emissions. No one would quarrel with that. In fact, the nation's industries would cut their emissions to the bone if no cost to society were involved. But huge costs are involved. The meaningful question which is not addressed is "will the environmental benefits resulting from a 10 million ton SO_2 reduction be reasonably commensurate with their cost?" We have some feel for the compliance costs that would be imposed by H.R. 3030: EPA says about $4 billion per year (Tr.p.46); the electric utility industry says about $6 billion per year. But we are only now beginning to get a sense of what the resulting environmental benefits will be -- and they appear to be meager.

For example, aquatic acidification in the Northeast has always been regarded as the principal focus of the acid rain concern. It has driven this legislation for the past decade. However, we are now told by NAPAP that without acid rain legislation,

> "in the northeast the chemical status of the lakes would stay approximately the same, over the next 50 years." (Dr. Mahoney, Tr.p.18; see also Tr.pp.42-43)

So much for the driving force!

In his testimony, Dr. Mahoney also indicated that under an SO_2 emission reduction scenario in the range of 10 million tons the percentage of acidified lakes in the Northeast would be reduced from 5% to 4% over the next 20 years (Tr.p.44). This represents the restoration of 26 lakes. Over a 50-year period -- a full half century -- NAPAP projects that a total of only 75 acidic lakes in the entire Northeast would be restored as a result of a 10 million-ton reduction program. Bear in mind that this is the primary environmental benefit that can be expected to result from an annual national expenditure of $4 billion to $6 billion. Using U.S. EPA's lower figure ($4 billion), this equates to $53 million per lake per year. (Even if the number of restored lakes were double the number projected by NAPAP, the cost would still be in excess of $25 million per lake per year.) Also, it should be understood that much of this benefit could be achieved more quickly and at an infinitesimal fraction of the cost through lake liming (Tr.pp.62-65 - testimony of Dr. George Hidy of EPRI). Furthermore, as testified to by Mr. Walter Kretser, Project Director of the New York State Adirondack Lake Survey Corporation, at the October 5 hearing, it is not known whether there are more or less acidic lakes in the Adirondacks than there were in 1900 (Tr.p.67). This confirms the possibility that many of the presently acidic lakes were acidic prior to the industrialization of our nation.

Does the restoration of 75 lakes over a 50-year period justify an increase in electric rates throughout the nation -- particularly in the Midwest where such increases will approach rate shock? Does it justify substantial job losses in the coal mining industry and probable plant closings in such key electricity-intensive, marginal industries as aluminum, steel, chemicals and autos -- especially when much of this benefit could be obtained more cheaply by liming?

Supporters of acid rain control legislation will argue that aquatic benefits are not the only environmental benefits that will result from the proposed legislation. They will argue that there are other benefits which, taken together with the aquatic benefits, justify the costs of the bills. Are there in fact such other benefits and, if so, how significant or certain are they?

This question is best answered in two pages of briefing notes with covering letter written by Dr. Mahoney to Nancy Maloley of the Office of Economic and Domestic Policy, dated April 26, 1989 (a copy is attached to my testimony as Appendix A). In these briefing notes, Dr. Mahoney very concisely summed up the state of NAPAP's current knowledge regarding these non-aquatic environmental benefits as follows:

> "The only benefits generally agreed to be expected from new acid rain controls will be improvements in acidic and sensitive lakes and streams. There is no consensus that improvements in other effects categories would be significant. Possible health risks associated with the acid rain pollutants (acid aerosols) are currently being evaluated. Improvements in degradation of exposed materials and in atmospheric visibility would occur, but may not be large. There is no evidence of widespread forest damage from acid rain, with the possible exception of mountaintop exposures to acidic

> clouds. (Ozone can cause forest damage in some regions, but SO_2 controls will not improve such ozone damage.)"

So much for the other benefits!

Dr. Mahoney, in his briefing notes to Ms. Maloley, went on to state that "a control strategy highly focused on the Ohio Valley and other Midwestern power plants may not be optimal" -- an observation obviously ignored by the draftsmen of these bills. He also said that "[i]f no critical acid rain effects are demonstrated to require more rapid control, a post-2000 (e.g., 2003-2005) deadline for full control implementation should be considered, to allow adoption of CCT [clean coal technologies] options for many repowering applications." We read this as a suggestion by the NAPAP Director that, on the basis of current scientific knowledge, the Phase II compliance date could be extended to 2003 or 2005 without doing violence to environmental values.

. Apparently sensitive to the paucity of environmental benefits being reported by NAPAP, William Rosenberg, Assistant Administrator of EPA, at the October 5 Senate hearing testified as follows:

> "...we also went beyond the NAPAP study to focus on health and visibility studies that were being done by others to deal with the health and visibility questions, as well as ecological questions, and melding them all together. That was the basis for the present determination that the time for action was now." (Tr.p.33; emphasis supplied.)

We construe Mr. Rosenberg's remarks as evincing a recognition by U.S. EPA that the results emerging from the $500 million NAPAP study -- the most comprehensive environmental study ever undertaken -- fall short of justifying a multi-billion dollar

SO_2 reduction program and that in order to shore up the sagging benefits side of the equation, EPA had to reach out into other areas for makeweights to "meld" with the NAPAP results.

In this connection, I would like to call to your attention a Progress Report by EPRI (the Electric Power Research Institute) dated January 9, 1990. (A copy is attached to my testimony as Appendix B.) The EPRI Progress Report constitutes a status report with respect to an ongoing EPRI study that is expected to be finalized in February. It compares the costs and benefits that would result from H.R. 3030 with those that would result from a vigorous clean coal technology (CCT) alternative. The environmental effects portion of the EPRI Progress Report is based on information publicly available as of January 1, 1990, including data and results from over a decade of research by EPRI, NAPAP and others.

The EPRI Progress Report indicates that a 50% reduction in SO_2 emissions will be achieved under either scenario within 40 years; but that the approach embodied in H.R. 3030 will cost the nation between \$140 billion and \$400 billion more than the CCT approach. Since the environmental benefits being projected for a 10 million-ton SO_2 reduction are quite limited, the difference in environmental effects between H.R. 3030 and the CCT alternative (except possibly for a slight, temporary improvement in visibility) are so negligible as to be virtually indiscernible. However, the CCT program, despite its much lower cost, carries with it a number of significant benefits that H.R. 3030 does not possess. They are: (i) up to 4% less CO_2 emissions by 2050; (ii) up to 17% less solid wastes generated by 2050; and (iii) up to a 4% improvement in generating efficiency -- all at a cost at least $140 billion less to the American public.

Mr. Chairman, I realize that we are told that the politics have outrun the science (on this most scientific of all issues); that it is not productive to talk about the science; and that no matter what the science says, a bill will be enacted this year. Maybe so. Nevertheless, in view of the recent scientific information disclosed by NAPAP, we are emboldened to suggest that the Congress ought to step back and take a fresh look at this legislation -- perhaps deferring its enactment until the Congress has before it the cost-benefit analyses that are being prepared by NAPAP (after 10 years of work) as part of its Integrated Assessment and which will be available later this year. In a rational world, this would be the obvious course to take.

However, if the politics are such that the Congress feels that it must act right now, why then must it be an extreme bill like H.R. 3030 or the even harsher S. 1630? In these bills, we are presented with certain key parameters which it is insisted are immutable, i.e., a 10 million ton reduction, the year 2000 compliance date and the emissions cap. We submit that the "tyranny of round numbers" should not be uncritically accepted. At a minimum, these inflexible parameters should be revisited by the Congress in view of the very limited environmental benefits that we now understand will result from all this.

For example, why 10 million tons? How much of a loss in environmental benefits would there be if we went to 8 million tons? Based on NAPAP's findings, the difference in benefits would be imperceptible. However, the reduction in cost would be very dramatic. EPA Administrator Reilly, during a June 23, 1989 Knight-Ridder Newsmaker Luncheon, stated that an 8 million ton bill would cost the nation $2.2 billion per year whereas a 10 million ton bill would entail an annual cost of $3.8 billion. While we believe that both numbers are unrealistically low, we agree that the ratio between them is essentially correct. Therefore, by going from a 10 million to an 8 million ton reduction, we would (using EPA's own figures) cut the cost of the legislation by a whopping 42%. Now would someone please advise the Congress what the loss in resulting environmental benefits would be! Our reading of NAPAP tells us that you could not even see the difference.

With respect to the Administration's second immutable parameter, the year 2000 compliance date, it has already been pointed out that the Director of NAPAP in his April 26 briefing notes to Nancy Maloley appears to have suggested that the 2000 date could be extended to 2003 or 2005 without prejudicing environmental concerns. The principal virtue of such an extension is that it would provide the innovative clean coal technologies with some breathing room in which to grow. The 2000 Phase II compliance date will force utilities to choose between conventional scrubbers and CCT in the 1995-96 time frame because of the lead time needed to design, fabricate and install scrubbers should scrubbers be the compliance method selected. However, the major CCT repowering technologies will not have been commercially proven until 1998-2000. Thus, if a decision must be made in 1995-96, the concern is that the utilities will have little choice but to opt for the proven technology (conventional scrubbers) rather than take a chance on commercially unproven CCT. This can only have the effect of stultifying the development of the CCT program and it is upon the success of that program that the future use of our nation's vast coal resources depends. We would urge the Congress to take another look at the year 2000 compliance date in the light of the negligible environmental benefits now expected to result from either of these bills.

With respect to the Administration's third immutable parameter, the emissions cap, I have earlier in my testimony pointed to numerous serious problems which are created by this cap. In the light of the recent NAPAP findings, the cap's elimination would not be expected to have any noticeable effect upon resulting environmental benefits since those benefits are expected to be quite slim in any event, and also because all new power plants are required to limit their emissions to the maximum extent permitted by ever-improving control technology. We would urge the Congress to revisit the emissions cap.

Unless pending acid rain legislation is moderated substantially, those who lose their jobs as a result will legitimately insist on knowing what the environmental benefits were that required the sacrifice of their livelihoods. In this connection, I have attached as Appendix C to my testimony the statement of Emmet Boyle, Chairman and Chief Executive Officer of both Ormet Corporation and Ravenswood Aluminum Corporation, which was filed in October of last year with the House Subcommittee on Energy and Power, chaired by Congressman Sharp. Ormet and Ravenswood are primary aluminum producers. They are located along the Ohio River in Ohio and West Virginia, respectively. These two smelters account for 11% of our nation's primary aluminum reduction capacity. Some of the aluminum produced at these plants is used for vital U.S. defense systems and America's space shuttles. They employ 2,300 workers with an annual payroll and benefits of $203 million. They are electricity-intensive facilities and constitute the two largest customers of the American Electric Power System. The impact upon these two smelters which Mr. Boyle foresees from H.R. 3030 is very sobering. To justify this kind of an impact, the environmental benefits had better be there and they had better not be slim.

If the Congress decides not to defer action until it has the results of the NAPAP Integrated Assessment, and if the Administration's immutable parameters remain immutable, then we would urge at the very minimum that certain of the features of S. 1630 that make it even more burdensome than H.R. 3030 be deleted.

I make particular reference to the fact that the Senate bill has shortened by one year the compliance time for Phases I and II contained in H.R. 3030. You may recall that the President's Fact Sheet regarding his Clean Air Plan issued June 12, 1989 stated that all dates in the Administration's acid rain proposal "assume enactment of this legislation by December 31, 1989" (p.4). The clear implication of that statement was that if the legislation was not enacted by the end of last year, consideration would be given to extending those dates further into the future to correspond with reality. Well, the legislation was not enacted last year -- but instead of moving the compliance dates further into the future or at least leaving them alone, the Senate Environment Committee has actually shortened the time for compliance by one year in each Phase. This is a stellar example of environmental machismo. Assuming enactment of a bill late this year, S. 1630 provides in Phase I only four years for the development and approval of compliance programs and the design, manufacture, installation and cut-in of scrubbers. This time frame is totally inadequate and, since we cannot do the impossible, will necessitate an amendment to the legislation at some later date. By lopping one year off of the Phase II compliance deadline, S. 1630 would drive yet another nail in the coffin of the clean coal technologies program. We urge the Senate to revert to the compliance dates contained in H.R. 3030.

We also urge that the clean coal technologies incentive provisions contained in H.R. 3030 be incorporated in S. 1630. The Senate bill is shockingly insensitive to the importance which the clean coal technologies program holds for the nation's energy and environmental future.

Furthermore, we urge that the Senate bill adopt the approach taken to NO_x control in H.R. 3030. The NO_x emission rate limits contained in S. 1630 could require the use of emission control technologies that have not been adequately demonstrated in commercial application in the United States. S. 1630, therefore, could result in the imposition of infeasible or exorbitantly expensive emission control requirements. In contrast, the NO_x emission reductions under H.R. 3030 would be achieved through the use of low-NO_x burners which have been commercially demonstrated for many boilers and which would achieve substantial reductions in NO_x emissions without placing an unreasonable financial burden on U.S. industry by compelling the use of untested and possibly unreliable technologies.

Also, S. 1630 takes away 2% of each utility's allowances. This forces the utilities to reduce their emissions below the compliance levels mandated by Phases I and II. This means that even under U.S. EPA's very conservative view with respect to 1980 SO_2 emissions, S. 1630 will yield more than a 10 million ton reduction. We estimate that the additional reduction required would be somewhere between 110,000 tons and 180,000 tons -- each at the most expensive marginal cost of control. This renders an onerous bill that much more onerous; it exceeds one of the Administration's "immutable parameters", i.e., the 10 million tons; and it is totally unwarranted by the sparse environmental benefits currently being projected by NAPAP. Its only purpose is to provide insurance against the possibility that the volume of emissions trading may be insufficient as a result of the emissions cap. It is a heavy price to pay for a hedge against such a concern. We urge that this provision be dropped from S. 1630.

Finally, both S. 1630 and H.R. 3030 define "new units" as those which go into service after the enactment of the legislation. All other environmental legislation of which we are aware define "new units" as those the construction of which commences after the enactment of the legislation. Under the pending bills existing units receive emissions allowances, whereas new units do not. We submit that it is grossly unfair not to treat as existing units those units which have been under construction for years and as to which hundreds of millions of dollars have already been expended in good faith. S. 1630 and H.R. 3030, in this respect, change without notice long established ground rules on which the utility industry and the general business community have come to rely. New units ought to be redefined as those upon which construction commences after the date of enactment.

In conclusion, Mr. Chairman, I would remind this Committee and through it the entire Senate that S. 1630 is the product of the Senate Environment and Public Works Committee. The heartland of our nation has no representation on that Committee. Ours is the region that is most heavily impacted by this bill -- but we have had virtually no input into it. We would hope that an awareness of this fact will cause this Committee and the Senate as a whole to approach S. 1630 with a healthy skepticism and a critical eye and not allow it to be rushed through without searching scrutiny and due deliberation. Thank you.

APPENDIX A

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

722 JACKSON PLACE, N.W.
WASHINGTON, D.C. 20503
202/395-5771

April 26, 1989

MEMORANDUM

TO: Nancy Maloley
Associate Director
Office of Economic and Domestic Policy

FROM: James R. Mahoney
Director, NAPAP

SUBJECT: Short Briefing Notes on Technical Acid Rain Issues

In response to your request today, I am attaching a short briefing statement on technical aspects of the acid rain control issue.

Because of the short time available, I have not been able to review this statement with the representatives of the NAPAP agencies. I am sending information copies to the NAPAP agency representatives at this time, and I will advise you promptly if any substantial disagreement arises during their review of these notes.

Attachment

Copies to: Interagency Science Committee
Interagency Policy Committee

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

Briefing Notes -- April 26, 1989

James R. Mahoney

BACKGROUND

NAPAP was established under the authority of the Acid Precipitation Act of 1980 (PL 96-294) to develop the technical information needed for policy decisions pertaining to acid rain. NAPAP's research and assessment expenditures have exceeded $450 million since program activity began in 1982.

PL 96-294 requires NAPAP to analyze acid rain causes, effects and control strategies, by conducting policy relevant (1) scientific studies, (2) technology evaluations, and (3) economic analyses.

The principal NAPAP participating agencies include EPA, DOE, USDA, NOAA, DOE and CEQ. NAPAP is directed by a Joint Chairs Council chaired by the EPA Administrator and including a senior Presidential Appointee from each of the other five key agencies.

BENEFITS OF ACID RAIN CONTROL

The only benefits generally agreed to be expected from new acid rain controls will be improvements in acidic and sensitive lakes and streams. There is no consensus that improvements in other effects categories would be significant. Possible health risks associated with the acid rain pollutants (acid aerosols) are currently being evaluated. Improvements in degradation of exposed materials and in atmospheric visibility would occur, but may not be large. There is no evidence of widespread forest damage from acid rain, with the possible exception of mountaintop exposures to acidic clouds. (Ozone can cause forest damage in some regions, but SO_2 controls will not improve such ozone damage.)

Recent studies indicate possible lake and stream impacts throughout the East (i.e., not limited to the northeastern United States and southeastern Canada). This suggests that a control strategy highly focused on Ohio Valley and other midwestern power plants may not be optimal.

The time scale for either further acidification or recovery of lakes and streams is believed to be long (e.g., decades) in the Northeast, and is still being evaluated for other eastern regions. Insofar as the time scale for changes is long, control strategies which make significant use of clean coal technologies (CCT) are perferred, compared to retrofit scrubbers.

CONTROL STRATEGY IMPLICATIONS

CCT has several benefits compared to retrofit scrubber use, including energy efficiency (beneficial for global climate impacts), significant NO_x emission reductions, and more manageable wastes. If no critical acid rain effects are demonstrated to require more rapid control, a post-2000 (e.g., 2003-2005) deadline for full control implementation should be considered, to allow adoption of CCT options for many repowering applications.

A flexible specification of control requirements (examples: a two-phase approach with an updated evaluation in the mid-1990s, and marketable emission reductions) would optimize the benefits achieved by the national investment in controls.

NAPAP ASSESSMENT REPORTS

The NAPAP assessment reports to be completed during 1989 and 1990 will provide the following:

- Findings of the major scientific and technological studies now underway. Some changes in current information about effects, benefits and control technology are likely to result.

- Critical review and consensus building for the many disputed views about acid rain effects and control approaches. (The NAPAP International Conference on Acid Rain scheduled for February 1990 will be a major consensus building activity.)

- Comparative evaluation of control strategies, to report the most effective and cost efficient options.

APPENDIX B

AN EVALUATION OF TWO ALTERNATIVE SO_2 EMISSIONS REDUCTION STRATEGIES

PROGRESS REPORT

EPRI

January 9, 1990

MJG.900115-P

Best Available Information

1. This evaluation is based on information publicly available as of January 1990, including data and results from over a decade of research by EPRI, NAPAP, and others.

2. The analyses reflect, in part, the professional judgment of EPRI staff and contractors, in providing a concise interpretation and synthesis of available information.

3. This evaluation is broad and comprehensive in the sense that it considers:

   - a variety of factors governing emissions control
   - geographic resolution of source and receptor areas
   - conversion of SO_2 to sulfate
   - atmospheric transport
   - wet and dry deposition
   - impacts on lakes, streams, forests, soil conditions, materials, visibility, CO_2 emissions, and solid wastes

4. Even with the best available information, uncertainties remain when estimating future environmental effects. Using a set of scenarios, or a range of plausible assumptions, shows whether or not the choice between two (or more) alternatives changes when one varies assumptions or predictions of future outcomes.

TWO ALTERNATIVE SO_2 EMISSIONS REDUCTION STRATEGIES

- Emphasis on retrofit of controls

  Example: The Bush Clean Air Act Proposal

- Emphasis on advanced generation technologies

  Example: A Clean Coal Technology Alternative

Alternative Strategies

1. The Bush Clean Air Act Proposal includes requirements for a 10 MTPY SO_2 reduction by the year 2000 relying principally on the retrofit of scrubbers and fuel switching. Subsequent emissions are capped locally at the level achieved by the year 2000.

2. The Clean Coal Alternative assumes relatively rapid deployment of new clean coal technology in new and repowered plants. There are no requirements for fuel switching or the retrofit of scrubbers to existing plants. The reduction is achieved through assuming a 95% SO_2 control requirement on new power plants and 90% SO_2 control on repowered plants.

3. Both alternatives would lead to reduction in utility SO_2 emissions of over 50% within 40 years.

COMPARING THE RETROFIT PROPOSAL WITH A CLEAN COAL ALTERNATIVE

- The scientific evidence obtained does not suggest a need for urgent action on retrofit.
- The differences in ecological effects between the two alternatives are small.
- The retrofit alternative offers no significant gains in other environmental goals.
- A clean coal alternative offers lower CO_2 emissions, significantly reduced solid wastes, higher energy efficiency, and significantly lower costs.

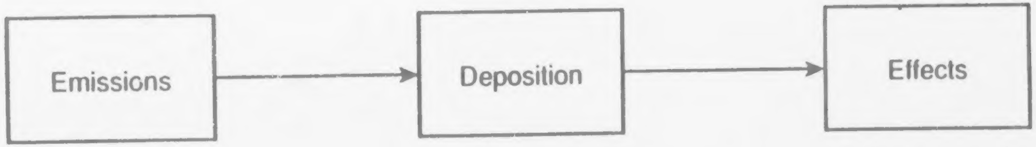
Comparing the Retrofit Proposal with a Clean Coal Alternative

1. At current deposit levels, lake acidification, forest damage, and other impacts are likely to change slowly, if at all.

2. The Retrofit Proposal tends to freeze technology and efficiency, and offers no measurable gains apart from a possible, interim improvement in visibility.

3. The Clean Coal Alternative is both less costly and offers demonstratable improvements in other environmental goals including energy efficiency, reduced solid waste and reduce CO_2 production.

EVALUATION APPROACH



Multiple scenarios
for each alternative
strategy

Multiple scenarios
to reflect a plausible
range of assumptions
regarding transport and
conversion

Multiple scenarios
for each category
of effects

Compare alternatives under
each set of scenarios

S1236 12/84

Evaluation Approach

1. A range of scenarios were defined for each key factor: emissions, deposition, and effects.

2. 10 different scenarios, varying assumptions on technology mix, demand, and other factors, have been prepared by the EPRI Generation and Storage Division.

3. A base case or best estimate of deposition was developed using a semi-empirical model based on 5 years of observations from 20 Eastern U.S. Sites and other currently available data. Additional scenarios reflect the range of variability in the underlying data. In each case, deposition is calculated for a representative set of specific receptor locations.

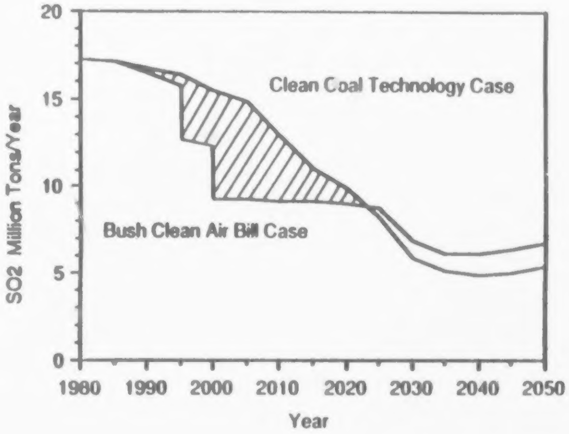
4. The scenarios vary by effect category. For example, the ILWAS model is used to calculate impacts for a representative set of lakes. A set of scenarios, reflecting the range of plausible assumptions, are used to extrapolate from the representative lakes to all lakes.

5. The two alternatives were compared for a wide range of these scenarios to evaluate how varying assumptions and remaining uncertainties influence the comparison.

ARE THE ENVIRONMENTAL BENEFITS WORTH THE COST?

The Retrofit Proposal will
reduce SO_2 emissions by about
90 million tons through 2020,
as compared to a clean coal alternative...

UTILITY SO2 EMISSIONS - CONTIGUOUS UNITED STATES



... at an added cost that would exceed $120 billion (constant 1989 dollars)

Evaluation of Future SO_2 Emissions and Costs

1. Annual utility SO_2 emissions and incremental capital and annual costs were estimated over the period 1980 to 2050 for the two SO_2 reduction alternatives using the EPRI model discussed in the "1988 Interorganizational Workshop on Future Utility SO_2 Emissions," EPRI Report No. GS-6578, November 1989.

2. Ten different scenarios were investigated to determine the sensitivity of the results to changes in the major assumptions such as annual load growth, rate of introduction of clean coal technologies, plant retirement age, etc.

3. The EPRI SO_2 emissions model uses the technology mix projected by NERC for the 1987-1996 period and then assumes constant regional capacity reserve margins and growth rates beyond 1996. The 1985 SO_2 emissions are based on NAPAP estimates.

4. Clean coal technologies (IGCC and FBC) were employed to repower between 15% and 45% of the eligible existing capacity and were further assumed to represent between 0% and 100% (at varying growth rates) of the new capacity additions in the 1996-2050 period. In general, it was assumed that the deployment of the CCT's would be delayed in the retrofit scenario due to the fact that under this scenario the financial resources and the engineering talent of the electric utilities will be devoted to implementing the retrofit option which would probably result in a significant delay in the commercial demonstration and deployment of the CCT's. These delays could range between 0 and 30 years.

5. For annual peak demand growth rates ranging from 1.15% to 2.8%, the cumulative incremental annual costs savings attributable to following the clean coal scenario rather than the retrofit scenario could be expected to range from \$120 billion to \$400 billion (expressed in constant 1989 dollars).

WHAT ARE THE DIFFERENCES BETWEEN THE TWO STRATEGIES?

- Other Implications -

CO_2 Emissions	Up to 4% less under clean coal strategy by 2050.
Solid Wastes	Up to 17% less under clean coal strategy by 2050.
Energy Efficiency	Up to 4% improvement in efficiency of resource use with clean coal technologies.

WHAT DOES THE SCIENCE TELL US?

- To date, the effects of acid deposition are small.
- Given current deposition rates, there will be no catastrophic ecological changes and other identified effects will be small.
- The difference in effects between the two alternatives will be even smaller.

What Does the Science Tell Us?

1. Knowledge on all aspects associated with SO_2 emissions and acid deposition has been substantially enhanced over the last decade. Comments on this page are based on this improved state of information.

2. "In the Northeast, minimal changes [in lake acidity] are projected to occur at current levels of deposition..."
   - James R. Maloney, testimony to Senate Subcommittee on Environmental Protection, Oct. 5, 1989

3. "In their investigation of the effects of acid rain on forests...the scientists say they have turned up no smoking gun."
   - NY Times, Sunday, December 31, 1989

4. SO_2 Emissions in the Eastern North America have leveled off or declined since the 1970's.

5. At present, 4.2 percent of the lakes in the National Surface Water Survey are acidic (from all causes), and similar percentages of Canadian lakes are also acidic (from all causes). At current deposition levels the extent of acidification is unlikely to change for decades.

6. At present, a few thousand acres of high elevation red spruce forest show damage due to a collection of stresses that may include acid deposition (red spruce is not a commercial timber). The extent of damage to red spruce is not likely to increase rapidly at current deposition levels, and reduction in SO_2 emissions alone is insufficient to reduce the damaging stresses. Other tree species do not show any evidence of acid deposition damage at current deposition levels.

7. Crop damage from acid deposition has not been found.

8. Either alternative will provide some reduction in effects as compared to the status quo. However, the estimated difference in improvements between the two alternatives is a very small - for example, on the order of 0.1 percent of all lakes.

WHAT ARE THE DIFFERENCES BETWEEN THE TWO STRATEGIES?

- Effects of SO_2 Emissions-

Lake Impacts	Extent of lake acidification differs by a fraction of one percent of the total lake area.
Forest Impacts	Likely to be no differences beyond measurement uncertainty.
Crop Impacts	No adverse impacts under either strategy.
Materials Damage	No difference in materials maintenance practices.
Visibility	Retrofit 10-20% better in the 2000-2010 time period but essentially the same later.

Comparing A Retrofit Proposal With a Clean Coal Alternative

1. Additional analyses are underway to refine these estimates.

2. The ranges reflect differences between the alternatives over a range of plausible assumptions.

3. Lake impacts are based on ILWAS analyses extrapolated to all lakes. Differences between the alternatives are on the order of 0.1% of all lake acreage; the number of lakes with differences in fish population impacts is likely to be even smaller.

4. Between 1995 and 2015, the retrofit strategy would yield a somewhat greater improvement in visibility. The differences of 10-20% in summer time average mid-day visibility would occur over a 10 year period between 2000 and 2010. The difference between the two strategies is on the threshold of being noticeable by the public.

APPENDIX C

Response to Proposed SO2 Amendments

By
R. Emmett Boyle
Chairman and Chief Executive Officer
Ormet Corporation and Ravenswood Aluminum Corporation

Filed with the
House Subcommittee on Energy and Power

I am grateful to the subcommittee for inviting me to present my views on the impact of the Administration's proposed SO2 amendments to the Clean Air Act. Protecting our nation's environment is an important goal, and one we all should support. As we strive toward this objective, the people of this nation, and the members of this Congress, must not lose sight of other, equally important goals, namely jobs for our people and fair competition for our industries.

I do not speak as a scientific expert or a political analyst. My interest, and my life's work, is the aluminum business. I have spent 24 years in that business, starting as a mechanical project engineer at the Ravenswood plant in West Virginia. Another thing I can speak of with authority is the Ohio Valley. I have lived there, studied there and worked there for close to a quarter century.

The American aluminum industry and the future of the Ohio Valley are my primary concerns. My great fear is that these two matters will be overlooked during the debate on this legislation. This would be a tragedy for the country in general and the Ohio-West Virginia area in particular. While you deliberate on environmental issues as they relate to energy and power, please do not forget the economic environment of a vital American industry. Please do not forget the economic environment of a vital American community.

Overview of Companies

Let me put my remarks in context by giving you a brief sketch of my two companies. Ormet Corporation and Ravenswood Aluminum Corporation are located in the Ohio Valley, which as you know is already an economically depressed area. Both are primary aluminum producers, with a combined capacity of 915 million pounds per year. Ormet is headquartered in Hannibal, Ohio, where it has a six-potline smelter. Ormet also has an alumina facility in Louisiana that provides raw material to the Ohio Valley smelter. Ravenswood is located further down the Ohio River in Ravenswood, West Virginia, where it has a four-potline smelter and an aluminum sheet and plate fabrication plant.

The Ormet and Ravenswood smelters account for approximately 11 percent of our nation's primary aluminum production capacity. That is a significant contribution, which we in the Ohio Valley are proud to make. The Ravenswood fabrication plant makes a variety of important products for commercial use, including the aircraft industry. We make aluminum products for vital U.S. defense systems, and our aluminum plate is used on America's space shuttles.

Ormet and Ravenswood are not small operations. They are a very important part of the U.S. aluminum industry. That is why we must take into account the impact this proposed sulfur dioxide legislation will have on these operations. I am sad to say that the bill before you places Ormet and Ravenswood in grave jeopardy. No matter how well intentioned, this legislation is a threat to a critical sector of the American aluminum industry and a threat to the economic survival of the Ohio Valley.

Crippling Economic Impact

Why do I say this? It is a matter of simple arithmetic. The two power plants that provide electric power to the Ormet and Ravenswood facilities are on the list of plants earmarked by the administration for substantial SO2 reduction. The immediate impact of complying with this bill's provisions would be to increase the cost our supplier, American Electric Power, would have to charge for our electric power by as much as 40 percent. If either power plant were shut down, our increase in electric power cost would be much, much more.

Such a cost increase would be bad enough for most businesses. For an aluminum producer, it would be catastrophic. This is because electricity accounts for up to 35 percent of the cost of producing aluminum. We are an energy-intensive industry. Electricity is a raw material in the process of producing aluminum.

Neither Ormet nor Ravenswood could escape such a drastic cost increase. Ohio Power, an operating subsidiary of AEP, supplies Ormet's and Ravenswood's electric power through the Kammer and Muskingum River power plants, respectively. The Public Utility Commission of Ohio has ruled that both of these plants are "dedicated facilities," which means they are legally dedicated to providing power to our smelters. All costs of providing power are passed through to us. Our contracts with Ohio Power Company stipulate that both aluminum companies are directly billed for all costs of operation, maintenance and capital. Therefore, we, and not the power company, or its other customers, would have to bear all costs of compliance with acid rain legislation.

That is an unfair and impossible burden. It singles out and penalizes the aluminum smelters in the Ohio Valley. It nullifies our efforts to preserve the industrial base of our region and to keep the American aluminum business competitive.

Global Competition

We can't succeed if our power costs increase by 40 percent or more. And I am not just talking about competing with other U.S. producers. The aluminum producers of the Ohio Valley are fighting to stay alive in a global marketplace. The U.S. only produces 52 percent of the primary aluminum it consumes. Approximately 20 percent is imported, and the rest comes through recycling.

Ironically, since 1980 the U.S. has seen its primary aluminum capacity slip from 5 million tons to 4 million tons per year. That's a 20 percent drop in our nation's production capacity. Some 14 primary aluminum smelters have shut down in this country since the early 1980s. Between 15,000 and 16,000 direct jobs have been lost. Why? Mostly because the U.S. does not have competitively priced electrical energy. On average, the U.S. aluminum industry pays 77 percent more for electricity than aluminum producers in other market economy nations. Some producers, like Ormet, are attempting to overcome that disadvantage by cutting other costs, boosting productivity and improving quality. This requires capital investment and modernization of our plants. We have just begun the process of restoring Ravenswood. All of this will be ruined if we are singled out to pay an additional 40 percent for our electric power.

The U.S. aluminum industry is in danger of losing more than a tenth of its remaining domestic production if this bill is passed. That's a statistic, and a big one. On a global level, it puts the national security of the Unites States at even greater risk, since we will have to rely more heavily on sources beyond our nation's borders. There is also a serious internal impact to consider, both at the regional and the personal level. I ask the members of this subcommittee not to forget the human cost of your decisions. What will happen to the people of the Ohio Valley if Ormet and Ravenswood are driven out of business by increases in power costs of such a magnitude?

Damage to Ohio Valley Region

A shutdown of the Ormet and Ravenswood smelting operations would mean the immediate loss of 2,300 jobs. This would result in a loss of more than $203 million in payroll and benefits that virtually supports the local economy. It would mean the loss of $6 million in taxes that substantially support the local governments and schools. Our fabrication, alumina and related rolling facilities would most likely follow, bringing the total loss of direct jobs in Ohio, West Virginia and Louisiana to almost 5,000. This doesn't count the fact that each of our manufacturing jobs generates approximately four indirect jobs. In other words, the likely effect of this bill on Ormet and Ravenswood is the loss of 20,000 jobs and hundreds of millions of dollars in payroll, benefits and taxes.

The Ohio Valley is already struggling with high unemployment. This legislation could prove a devastating blow to the economic health of our region.

The people of Ormet Corporation and Ravenswood Aluminum Corporation are well aware of the importance of protecting the environment. We support environmental protection measures that are reasonable, logical, and that take into consideration the jobs and livelihood of our people. We cannot support the present legislation because it forces us to bear all the costs of the government's plan. We simply can't afford to do that and hold our own against very stiff global competition.

If a tornado destroyed one of our plants, we would be able to appeal to the federal government for assistance to get us back on our feet. I fear that the Administration's proposal is a legislative tornado. It will sweep up many innocent people if it goes unchecked. I am appealing to this subcommittee to divert the path of this storm before it is too late.

Thank you.

The **Chairman**. Thank you very much, Mr. Dowd.

And finally, we will hear from Commissioner William A. Badger, with the Maryland Public Service Commission in Baltimore.

Mr. Badger.

STATEMENT OF WILLIAM A. BADGER, COMMISSIONER, MARYLAND PUBLIC SERVICE COMMISSION

Mr. **Badger**. Thank you, Mr. Chairman and members of the committee.

I should tell you, in addition to being a Commissioner for Maryland, that I serve as First Vice President of the National Association of Regulatory Utility Commissioners, and chair its Committee on Electricity.

From the outset, let me first emphasize that NARUC indeed does support acid rain legislation, has taken a position that it be carried out in an effective and efficient manner. And two, that it should encourage conservation. And three, that it would not interfere with the present federal and state regulatory process.

And with that, let me turn to the issues that were raised in your letter of invitation.

First, let me discuss the practical effect of the cap. Given this constraint, it appears that new capacity required to accommodate residential, commercial and industrial growth will only be acquired by constructing nonemitting capacity, such as nuclear. And I think we all know the kind of time frames and planning horizons that go with that kind of investment.

Another option is turning to low-emitting gas-fired capacity. And there are concerns that have been expressed bymany that deliverable quantities of gas at prices may not be sufficient to support capacity needs.

Those utility systems with already low emissions may have little ability to further reduce emissions and force them to rely on this novel but untested trading system.

Similarly, the emissions cap, coupled with bottlenecks in the power transmission system, may limit the availability of purchase power from other utilities, independent power producers, or co-generating facilities.

So there are some real concerns that the options that are going to be available may be illusory, and that a possible ration of electricity option may be inevitable.

The difficulties of operating under a cap were addressed in June by NARUC in a survey in which at that time 65 percent of the states preferred the use of emission rates.

And in saying that, I should tell you that while an emission rate approach is favored by many states to accommodate future growth, those states with little low growth or high-emitting generating units near retirement may find that a tonnage cap strategy is more appropriate.

But there are a couple matters of concern about the cap that I would like to bring to your attention.

Senator Bumpers brought one out much more than I can really articulate. Specifically, we refer to his concern in our testimony of the Arkansas situation.

We are concerned that the arbitrary selection of a 1985–1987 period for measuring emissions does not consider the kind of utility operating aberrations that have existed during that period, and certainly as Senator Bumpers has identified.

And we would urge you to consider possible amendments that more accurately reflect the normal operating condition sat a plant.

And to that end, it may be advisable that you consider a choice of either an 1985 to 1987 or a 1980 to 1983 period to more accurately reflect the operating conditions of the plant.

We just simply think it is inequitable to impose that kind of a stringent guideline on plants that may have had the kind of situation that Arkansas confronted, or other forced outages.

I would also point out that neither the President's bill nor S. 1630 contain any provisions that would permit deviations from the cap in the event of national disasters, such as Hurricane Hugo, or other unplanned events that may cause extended outages. It is an area that we believe needs to be addressed.

Another concern is the failure to include the approximate 10,000 industrial emitters in this country, sources that account for one-third of the Nation's SO_2 emissions.

Now, while we recognize the obvious difficulties of completely administering such a program with that quantity of emitters, it may be appropriate for you to consider establishing a size threshold for including industrial facilities in this legislation.

In our view it is simply irresponsible and inequitable and unsound energy policy for one category of sources to be required to bear the entire burden of the nation's efforts to address this problem, while other sources escape responsibility for reducing their own emissions.

Let me now turn to the cap.

Since this proposal represents a movement into uncharted waters, in which licensing of all new generating capacity may hinge upon the success of allowance trades, it is vital that we have an understanding and be comfortable with the probable behavior of the marketplace, as well as federal and state regulation, the electric industry, and independent power producers and co-generators.

NARUC is not convinced that the assumptions underlying the Administration's plan or S. 1630 are correct. The Administration in previous testimony has simplistically described the trading system as analogous to a checking account, in which a utility makes deposits and withdrawals and operates in a competitive market with freedom of entry and exit.

But despite these representations as to the simplicity and efficiencies of the trading system, NARUC has been unable to obtain from the EPA for a period now approaching four months even a preliminary working document which would outline procedures or address the perceived responsibilities of EPA, the FERC, the state public service commissions, the utility industry, independent power producers, or co-generators.

The absence of this information from EPA has effectively precluded the association from developing a position that would support this kind of mechanism.

And in this regard, we learned recently from other sources that EPA has executed a contract with a consulting firm to undertake the development of recommended procedures.

Let me outline again just some of the other concerns about trading.

Key to the trading system debate that is before you is the assumption that so-called dirty utilities will be willing to undertake the over-control, pollution control investments to gain such allowances and sell them for a profit on the market.

Such action on both the federal and state level will require that utility rates be increased above that required even for basic compliance. And some of these increases may reach as high as 17 percent, a consequence that we believe may obviously discourage over-control, particularly if up-front payments by the purchaser are not required, and under conditions where allowances may be revoked under the current legislation.

To be effective it is believed that the trading allowances should create virtual property rights for their owners. Under a proposal in which allowances can be limited, revoked, or otherwise modified by EPA, it is difficult for us to understand how any long-term contractual arrangement reflecting value or transfer ability could ever be consummated.

I would note that the trading proposal does not assign or provide allowance opportunities for independent power producers or co-generation facilities under PURPA. The absence of which may adversely impact emerging competition in the wholesale power market.

Similarly, why should interstate trading be allowed only during the post-2000 year period. It would appear that early trading would remove potential uncertainties over the prices at which allowances could trade.

We have also serious doubts that the 2 percent set aside in S. 1630, coupled with the arbitrary $1,500 per ton price, will have any effect other than to reduce the liquidity in the allowance market.

We believe that EPA's involvement in the trading system should be essentially mechanical. That is, acting as a repository or clearinghouse for reported allowance trades, reconciling the account of allowance buyers and sellers, and monitoring actual emissions in light of allowance holdings.

EPA should have no further role in regulating utility participation in the allowance market. This participation, we would respectfully suggest, falls under the purview of the FERC and the state public service commissions.

There have been a number of amendments suggested to perhaps prevent utilities and/or regulators from retaining or hoarding allowances. And I would respectfully suggest to you that you should not consider this as an evil term.

It should be remembered that it is the very inclusion of the tonnage cap provision that renders the administration of a trading program difficult, and will make allowances a scarce resource.

For this reason we believe it is necessary for utilities and state and federal regulators to establish priorities in an individual's use of emission allowances. These allowances may be needed to accommodate new plants construction or serve as an insurance policy for forced outages.

And since allowances are a scarce resource, there may be an incentive to holding them instead of trading them. It is unlikely that utilities or state regulators would order the retention of allowances beyond those they believe are necessary for prudent system planning.

And we should keep in mind to the extent allowances are held, the market may be to thin, a consequence that will jeopardize the market mechanism.

Finally, I should tell you that state regulators, many of them, object to the imposition of a trading concept which requires their utilities to compensate dirty utilities for trading allowances in which the seller of the allowance has higher emission rates, but lower utility rates.

To mitigate this concern it may be equitable to permit clean utilities to earn allowance credits for pollution control improvements that were previously undertaken and achieved emissions lower than existing new source performance standards.

Finally, let me turn to your issue on cost sharing.

S. 1630 has been hailed as a polluter-pay approach, wherein individual utilities would be responsible to pay for their own compliance costs without support from others in the form of direct cash subsidies.

With all due respect to the drafters of the bill, many regulators believe that it represents cost sharing designed to transfer income to those states classified as dirty utilities, to offset pollution control expenditures.

These regulators believe that individual states should be responsible for financing their own control strategies, since to do otherwise places them in the unhappy position of not only having paid for their own control program, but now being required to finance other states' pollution control investments as well.

And as I mentioned earlier, there is a strong opposition to subsidizing such investments for states which have lower utility rates but higher emission rates. And on the other hand, as has been brought out in opening statements today, regulators from states confronting very substantial costs of the kind of 17 or 18 percent, believe there should be in place a stronger cost-sharing mechanism to assist in mitigating the large cost associated with the program.

In conclusion, we appreciate this opportunity to present our views on this issue. We hope to continue work with Congress and the EPA as final legislation is developed. But absent a more complete explanation as to the manner in which the trading program would operate, we are unable to support the emissions trading program contained in S. 1630 or the President's bill.

And while hopefully this information will be forthcoming from EPA to alleviate some of our concerns, I should tell you that the specter of never ending contractual and jurisdictional disputes between utilities, the EPA, FERC, independent power producers, cogenerators, and the state public service commissions, may be too appalling to contemplate.

And for these reasons the so-called auction proposals maybe an attractive alternative and are now being examined by NARUC's

Committee on Electricity with a view toward communicating to you a final recommended NARUC position in early February.

In any event, we would believe that implementation of this novel program requires a close working relationship between the state regulatory commissions, the FERC, and EPA.

And to this end, in an effort to appropriately outline the respective roles of each agency in ensuing legislation, or the development of regulation, we would strongly urge the Congress to consider directing EPA to fund a joint study on the emission trading program with the National Regulatory Research Institute, our research arm.

This process, we think, would ease and simplify the implementation difficulties and clarify the roles of the participants.

Thank you very much, sir.

[The prepared statement of Mr. Badger follows:]

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

TESTIMONY OF THE

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
1102 INTERSTATE COMMERCE COMMISSION BUILDING
P.O. BOX 684, WASHINGTON, D.C.

PRESENTED BY

THE HONORABLE WILLIAM A. BADGER
MARYLAND PUBLIC SERVICE COMMISSION

ON

ACID RAIN LEGISLATIVE PROPOSALS

JANUARY 24, 1990

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Mr. Chairman and Members of the Committee:

My name is William A. Badger, and I am a member of the Maryland Public Service Commission. I am also First Vice President of the National Association of Regulatory Utility Commissioners, commonly known as the NARUC, as well as Chair of the NARUC Committee on Electricity. I will be testifying this morning both as an individual member of the Maryland commission and in my capacity as a representative of the NARUC. I intend to note which views are my own and which views are made on behalf of our Association.

The NARUC is a quasi-governmental nonprofit organization founded in 1889. Within its membership are the governmental bodies of the fifty States engaged in the economic and safety regulation of carriers and utilities. The mission of the NARUC is to serve the public interest by seeking to improve the quality and effectiveness of public regulation in America. More specifically, the NARUC contains the State officials charged with the duty of regulating the retail rates and services of electric utilities now operating the fossil fuel based generating stations central to the acid rain debate. These officials have the obligation under State law to assure the establishment and maintenance of such electric utility services as may be required by the public convenience and necessity, and to ensure that such services are provided at rates and conditions which are just, reasonable, and nondiscriminatory for all consumers. For this reason, the NARUC is uniquely situated to offer some insight into the manner in which the economic and financial consequences of acid rain legislation will be administered at the State level.

INTRODUCTION AND OVERVIEW

Mr. Chairman, you are to be commended for convening this week's hearings to discuss the energy policy issues implicated by the legislation now moving through the Senate and House that would establish a new program for the reduction and regulation of the precursor emissions which cause acid precipitation. My colleagues and I in State utility regulation greatly appreciate the opportunity you have given us to provide our views on this important issue. Given the prevailing wisdom that there will be legislation enacted this year, it is profoundly important that the impact of the legislation on our Nation's energy future be fully considered and taken into account as the various bills move forward.

The leading piece of legislation, now being debated on the floor of the Senate, is S. 1630, the bill reported late last year by the Committee on Environment and Public Works. Modeled in large measure on the legislation proposed by the President last spring, this bill would implement an acid rain control program comprised of the following basic elements: (1) a two phase process, to be fully implemented by the year 2000, to permanently reduce utility emissions of sulfur dioxide (SO2) and oxides of nitrogen (NOx) by 10 and 2.7 million tons respectively; (2) the establishment of a program of marketable allowances through which the owners of individual sources would be permitted to buy and sell their respective legal obligations to reduce emissions levels; and (3) a "polluter pays" approach wherein individual utilities would be responsible to pay for their own compliance costs without support from others in the form of direct cash subsidies.

There can be no question that an acid rain control program along the lines of this legislation will go a long way in determining the form and availability of energy supplies and uses in the future. Indeed, the letter of invitation I received from this Committee asks that we focus our attention on the energy policy implications of these three elements of S. 1630, "the emissions cap, the allowance trading system, and cost sharing." Since this legislation looks to regulated electric utilities for emissions reductions, there can be little doubt that the State commissions that regulate the rates and services of these companies will be directly affected by the bill's enactment. In addition, there will be indirect effects on all aspects of our national energy profile. Natural gas markets will be affected as utilities and other fuel users look to gas as the "environmentally benign fuel of choice." The legislation will undoubtedly place renewed emphasis on improving the efficient operation of electric utilities -- a movement well under way at the State level already. Even the nuclear option may be reborn through a new generation of so-called "inherently safe" generating plants.

The legislation will also greatly affect the emergence of competition in wholesale power markets, an issue to which this

Committee has recently devoted a great deal of attention. Clearly, the categorization of "affected sources", the establishment of "base lines" for measuring emissions reductions, and the construction and operation of the allowance trading system will play a large part in determining who provides new power capacity, what kind of plants are built, and where they are located. More broadly, the contours of the legislation will determine how we, as a society, balance the costs and benefits of environmental regulation against the costs and benefits of economic growth on a State, regional, and National basis.

POSITION OF THE NARUC

In October of last year, I had the honor of representing the Association's views on acid rain legislation at a hearing before the Subcommittee on Environmental Protection of the Senate Committee on Environment and Public Works. At that hearing, I stated the Association's support for workable, cost-effective legislation to reduce utility emissions of acid rain precursors. Based upon resolutions adopted by the NARUC (which are attached hereto) and the results of a survey of State commissions conducted by the NARUC Committee on Electricity, I was pleased to report the following three point position of the NARUC on acid rain legislation: (1) the Association supports a flexible control program which "permits electric utilities to achieve compliance in the most economic and efficient manner"; (2) we strongly oppose legislation which would interfere with or undermine the utility ratemaking process at either the State or Federal levels; and (3) we believe that the legislation "should encourage energy conservation as a long range strategy for reducing acid deposition."

These are still our views. Since the hearing, however, members of the Association have sought to work with officials at the Environmental Protection Agency (EPA) and the House and Senate Committees and Subcommittees of jurisdiction to ensure that the views of State regulatory commissioners are taken into account as the legislation continues to be crafted. Throughout these discussions, our involvement has been guided by the three principles I have just described, as well as a more immediate concern: we have attempted to ensure that the final legislation presented to the President for his signature is workable and sensible from the perspective of State agencies who will be called upon to regulate the rates and services of utilities covered by the bill. Not surprisingly, we have spent a great deal of time discussing the emissions trading system proposed by the President, as well as other trading alternatives we have been asked to consider.

To ensure that the NARUC membership is fully aware of the debate here in Washington, our Committee on Electricity is now in the process of again polling the State commissions on specific issues surrounding emissions trading. As we learn more from the results of our survey, we will of course report NARUC's position, including recommended amendments,to all of the relevant

Congressional committees, a process I envision will be completed in early February.

At this point, I would like to turn to the areas raised in the Committee's letter of invitation.

ENERGY POLICY IMPLICATIONS OF THE EMISSIONS CAP

As reported by the Committee on Environment and Public Works, S. 1630, like the Administration's proposal, would establish a permanent Nationwide cap after the year 2000 on annual emissions of SO2 by electric utilities of approximately 8.9 million tons. This cap would represent a phased reduction of emissions from 1980 levels of approximately 10 millions tons. SO2 emissions from no other sector of the economy would be subject to a similar cap.

The immediately apparent effect of the cap is in the post-2000 period, no electricity generating entity could increase its emissions of SO2 if by doing so, it would exceed the 8.9 million tons of emissions allocated to this industry by the legislation. Leaving aside for a moment the operation of the emissions trading system, it would appear that an entity seeking to generate electricity without pushing total emissions above the cap would have options markedly different than if the cap did not exist. With no cap, the emissions source could design, construct, and operate a plant in compliance with the New Source Performance Standards (NSPS) and other regulatory requirements then in effect. With a cap, the options change. Given the constraint of the cap, a utility seeking to acquire new capacity would face the following array of choices: construct non-emitting capacity such as nuclear and renewables, construct low-emitting gas fired capacity, reduce its own SO2 emissions to "make room" for the emissions from a new fossil-based plant, acquire sufficient "allowances" in the trading market to support a new fossil-based plant, purchase wholesale power and let someone else worry about the cap, or in the face of capacity constraints, ration electricity.

Given these apparent choices, what then would be the effect of the cap on the Nation's energy picture? First, it is readily apparent that the cap would provide a strong incentive for utilities to operate more efficiently in order to postpone their need to operate any new SO2-emitting capacity. Stated somewhat differently, the longer a utility can forego the need to construct and operate new (primarily baseload) fossil-based generating plants, the longer it can avoid worrying about the cap. To the extent that an aggressive conservation program, and perhaps life extensions of existing capacity, can forestall the need to make this decision, the cap will tilt our energy policy in favor of conservation and the efficient use of existing resources--clearly beneficial results of the cap which State regulatory commissions will seek to foster through their own efforts to promote least-cost strategies. In other words, with no other special incentives or credits, the cap constitutes a powerful incentive favoring aggressive utility conservation programs.

At some point, however, some utilities and regulators in some regions may find that despite efficiency improvements, the need to acquire new sources of supply is inescapable. At that point, the emissions cap begins to directly affect fuel, technology, and ownership choices. In our view, it will also directly affect, and perhaps lead to the restructuring of current power pooling arrangements.

I would not be honest if I failed to report that a significant number of State commissions are very concerned that under S. 1630, the "ration electricity" option I mentioned earlier, will be the inevitable result of the imposition of a cap, particularly in those States and regions experiencing substantial growth in electricity demand. Let me explain why: For some utilities, the array of options I have described may be illusory. Given the need for utilities to begin planning the construction of new capacity far in advance, non-polluting options such as nuclear, hydro, or renewables may not be viable or available within a reasonable planning horizon for a host of political and economic reasons well known to the members of this Committee. While gas-fired capacity may make sense, there are concerns that deliverable quantities of gas at affordable prices may not be sufficient to support all needed electricity capacity. Utility systems with low emissions to begin with may have little ability to reduce their own emissions to "make room" for new fossil based capacity, therefore forcing them to rely on the trading system, which in turn, may not work as well as advertised. Similarly, wholesale supplies may not be readily available from other utilities or independent power producers (IPPs) since these sources will also be constrained by the emissions cap or by bottlenecks in the power transmission system. At that point, the options have disappeared, and the utility could well be unable to meet the demands of its customers.

Will this unfortunate scenario occur post-2000? That, of course, is the fundamental policy question raised by S. 1630 and the Administration's proposal. Stated directly, the question is this: Given reasonable assumptions about the ability of utilities, their regulators and their customers to improve the efficiency of their operations, and given reasonable assumptions about the utility system's ability to transmit power from where it is generated to where it is in demand, and given reasonable assumptions that the trading system established in the legislation will work, is it possible or likely that utilities will be able to meet the Nation's need for power while emitting no more than 8.9 million tons of SO2 per year? Just as in the Congress, there is a lively debate going on within the NARUC on this very question: According to our Committee on Electricity survey, 63% of the State commissions appear to support the use of emission rates over the use of tonnage caps. As you address this difficult issue, we should be mindful that the choices will vary with the circumstances unique to each State. For example, an emission rate approach will be favored by certain regions of the country to permit reasonable economic growth, while other States that have enjoyed relatively little load growth might select a tonnage cap to be the least expensive control methodology. Similarly, those companies that have generating plants which are high emitters and nearing the end of their economic life may determine that a tonnage cap strategy might be more appropriate.

One NARUC concern involves the so-called baseline issue. We believe that in the adoption of specific emissions reductions to achieve compliance with the cap, that the legislation should not adopt, as S. 1630 does, arbitrary baseline years that fail to recognize aberrations that may have existed during that period. In this regard, I would report that many State commissions are concerned that coal fired capacity emitting below the 1.2 lbs/mmbtu rate would have to freeze emissions at 1985 rates under the legislation, which in the case of plants burning low sulfur coal to meet NSPS, will force the installation of scrubbers to maintain 1985 rates. Yet companies operating these plants will receive no tradeable allowances if the installation of the scrubbers results in "overcontrol."

We can agree, however, that if Congress decides to adopt a cap-based control program, that it strongly consider extending controls to non-utility sources. I base this conclusion on the fact that a great majority of State commissions responding to the survey of the NARUC Electricity Committee opposed limiting the application of the legislation to steam generating units. As S. 1630 now stands, non-utility sources are covered by the legislation only if they voluntarily "opt in" to the allowance trading system. In our view, it is inequitable and unsound energy policy for one category of sources to be required to bear the entire burden of the Nation's efforts to address this problem when other sources escape responsibility for the costs of reducing their own emissions. The clear assumption underlying a "utility only" approach is that utilities are monolithic monopolies indifferent to the costs of reductions, an assumption clearly in conflict with State and Federal policies which promote greater competition in this industry. More pointedly, those who suffer the consequences of acidic precipitation do not care whether an electric utility or some other source is the cause of their problem. Yet, the leading bills would allocate all of the costs to electric utility ratepayers despite the fact that over 10,000 industrial sources emit approximately one third of the Nationwide SO2 tonnage. On energy policy grounds, mandatory coverage of non-utility sources above a reasonable threshold through inclusion under a larger cap and participation in the trading program would have the additional benefit of providing more liquidity to the trading systems while spreading compliance costs to a larger universe of sources.

In summary, we believe that the imposition of an emissions cap will have profound energy impacts on electric utility markets and fuel markets. It now appears likely, however, that the 8.9 million ton cap will be a part of the legislation that Congress will enact later this year. In our view, this means that the emissions trading system proposed by the Administration and included with some minor modifications in S. 1630 must be workable, an issue which I would now like to address.

ENERGY POLICY IMPLICATIONS OF EMISSIONS TRADING

As originally proposed, the Administration's bill establishes an emissions trading system intended to reduce the aggregate cost of the utility industry's compliance with the 8.9 million ton cap on total emissions of SO2. As we understand the proposal, every year, EPA would issue "affected sources" a number of emission allowances each entitling an "affected source" to emit one ton of SO2. The utility owners of the affected sources would be able to emit SO2 in an amount represented by the number of allowances they hold, or, if they choose to reduce their emissions to a level below the number of allowances they have been issued, they are free to sell their "excess allowances" to other utilities. S. 1630 adopts this basic outline, with a few modifications which I will subsequently describe. As in the Administration's proposal, S. 1630 requires EPA to annually allocate allowances to the owner or operator of each "affected unit", which is defined as a unit "that has a tonnage-based emissions limitation obligation [under the bill] or opts to make emissions reductions voluntarily." As a general matter, affected units will be allocated sufficient allowances to support emissions rates of approximately 1.2 lbs. of SO2 emitted per million btus of heat.

Unlike the Administration's original proposal which would have required EPA to annually release all of the allowances counted by the bill, under S. 1630, EPA would retain 2% of the allowances through a pro-rata reduction in the allowances issued each affected unit. The purpose of this set-aside is to establish an EPA-controlled reserve of allowances which would be sold into the system as a last resort at a high price, $1500 per ton. Under either the Administration's proposal or S. 1630, no new generating unit could be operated by any entity unless its owner possessed sufficient allowances to cover the unit's actual emissions. This means, of course, that to preserve the 8.9 million ton cap, any entity which did not also own an affected unit, be it a utility or an IPP, would be unable to operate any new unit emitting SO2 unless it was able to purchase allowances in amounts sufficient to operate the plant in question.

The allowance trading system has been hailed as the first large scale effort to incorporate market-based principles into a program of environmental regulation. It has also been promoted as reducing the total cost impact of the program by 20 to 50 percent, depending on who is developing the estimates. To achieve these benefits, which NARUC supports, the allowance trading system must be workable. In that regard, approximately 94% of the States responding to our survey consider trading within a utility system to be desirable, while 92% favor intrastate trading and 59% support interstate trading. However, it is important to note that NARUC support for the concept of emissions trading was founded on obtaining maximum flexibility in the operation of inter and intrastate utility operations and regional power pools. In our view, the workability of various trading proposals is the issue of energy policy upon which the Congress must focus its attention.

I should report, however, that many States which have achieved low emissions through the investment of substantial ratepayer funds believe that the trading system proposed in S. 1630 is a form of subsidy whereby utilities in "clean" States are forced to pay utilities in "dirty" States for a commodity--emissions allowances--which is absolutely necessary for their own economic growth. Many State regulators believe that individual States should be responsible for financing their own control strategies since to do otherwise would place them in the unhappy circumstance of not only having already paid for their own control programs, but now being required to finance controls in other States as well. In some instances, this means that utilities with relatively higher electric rates and lower emissions will be forced to transfer funds to utilities now having lower rates and higher emissions. On the other hand, there are States who would argue that whether or not trading produces a subsidy in effect, it still offers "clean" States a lower cost compliance strategy than the implementation of a "command and control" alternative.

Emissions trading may be successful, i.e. will reduce the aggregate cost of compliance below the cost of a "command and control" alternative, if the market within which allowances are traded is sufficiently liquid to enable willing buyers and sellers to trade allowances for cash at a reasonable price. As an initial matter, this means that the owners of affected units, which under S. 1630 are the so-called "dirty utilities", must be willing to "overcontrol" their own emissions so that they will not need all of their annual allotment of allowances for their own purposes. It is obvious that these utilities would only "overcontrol" if the costs of doing so are less than the price that the "extra allowances" would obtain on the trading market. Entities required to obtain allowances for new units would only be willing to pay a price less than the costs of alternative strategies to operate the generating plants the allowances would support. The critical assumption underlying this proposal is that the allowance seller's cost of "overcontrol" will be lower than the costs the allowance buyer would incur through an alternative strategy, and that therefore, there would be mutual benefit if each were to trade in the market.

On the question of overcontrol, which is one of the key issues in the workability of the system as established by S. 1630, it is important to consider two points: first, that for the approximately forty States without "affected sources", overcontrol is not an option. To obtain allowances, they are utterly dependent on actions taken in the other States in which affected units operate. Second, with respect to these States (the so-called "dirty States"), overcontrol will only occur if utilities and regulators are willing to increase electric rates above the already high levels that mandatory reductions would cause. While we recognize that EPA believes that rate increases under its bill will be approximately 3% on a Nationally average basis, increases in the "dirty States" will be far higher--some estimates are as high as 17%. Increases of this magnitude may well discourage overcontrol, thereby limiting available allowances.

Therefore, while the theory sounds nice, and we do not doubt that there will be cost differences which a trading system could exploit, the trading system raises a number of concerns not over theory, but rather, whether or not the legislation will result in a workable program. In recent months, much has been made of the fact that the entities who will participate in this market-based system are themselves heavily regulated, i.e. that utility participation in the market will be subject to scrutiny by State and Federal regulatory commissions. The implication of this fact is that allowance trading would work but for the actions of regulators who will impede or penalize utility participation in the program. Indeed, we are aware of serious efforts on the part of some to amend the legislation to preempt or otherwise dictate the regulatory treatment of the economic and financial effects of utility decisions to create, buy, and sell allowances under the program. It is said that such amendments are necessary to prohibit State commissions from ordering utilities to "hoard" allowances, or to remove the risk that utilities will be "penalized" through post-hoc prudence reviews for their participation in the allowance trading system.

The NARUC strongly opposes any amendments to this legislation which would preempt or in any way interfere with the regulatory responsibilities of the State commissions or the Federal Energy Regulatory Commission (FERC). We submit that if there are potential problems with the trading system contained in S. 1630, they cannot be attributable to State utility regulation, and therefore, there is no more need to dictate the regulatory treatment of this issue than any other issue routinely decided in utility rate proceedings. In our view, despite their novelty, the ratemaking treatment of emission allowances will be similar to any other factor input utilities need to generate and sell electricity. Perhaps the closest analogy to existing regulation involves utility fuel purchases. Under current practice, utility purchases of primary fuels such as coal, gas or oil are subject to the scrutiny of State commissions seeking to ensure that a company's fuel procurement practices have been conducted in a prudent, businesslike manner. In our view, this regulatory scrutiny has had no discernible impact on the workability or competitiveness of fuel markets, nor has it induced utilities to avoid participation in such markets.

Therefore, we oppose suggestions that the acid rain bill should somehow insulate utilities from any risk that their participation in the allowance market--either as buyers or sellers--will be subjected to regulatory scrutiny. Specifically, we oppose suggestions that utilities who overcontrol their emissions in order to generate saleable allowances should be guaranteed the unfettered right to recover their costs whether or not they have been prudently incurred. While it seems absurd, there is no defensible reason why a utility should be able to automatically recover in its rates the costs of generating allowances if those costs exceed the price the utility can expect to receive when it sells. Nor should utilities purchasing allowances be insulated from regulatory scrutiny of their purchasing practices. Again, if a utility expects to recover the costs of its allowance purchases from its ratepayers, it cannot be given the unfettered right to purchase allowances at any price if its regulators find that other alternative control strategies could be implemented at lower cost.

We also oppose other suggestions that the bill should be amended to ensure that State regulators do not direct utilities to "hoard allowances." Such an amendment would be both unnecessary and unwise for the following reasons: first, there may be sound reasons why a utility would seek to bank or retain excess allowances for a period of time, rather than immediately throw them on the market. A utility may be planning to construct a new plant of its own which will need its allotment of accrued allowances in order to comply with the legislation. Or a company may seek to retain allowances as an insurance policy against unforeseen outages of cleaner capacity which necessitates the unplanned operation of a dirtier plant. In either case, the retention of allowances is a legitimate response by utilities and their regulators to changing conditions in local electricity markets and consistent with their statutory mandate to provide safe, adequate, and reliable service. Second, it is reasonable to expect that State regulators will not order the retention of allowances beyond an amount they consider necessary for prudent system planning. The reason is simple: allowances will be valuable commodities which can be sold to reduce a utility's overall costs of compliance.

Therefore, if the trading system established in S. 1630 proves unworkable, it will not be due to the decisions of State regulatory commissions. That does not mean that we believe that on its own terms, S. 1630 is the best approach. We are concerned with the trading program, for at least the following reasons.

First, if emissions trading is to work, the allowances issued by EPA must constitute virtual property rights for their respective owners. Simply stated, a market in allowances cannot work if participants fear that the commodity they are trading can be extinguished at the stroke of a pen. In our view, the Senate bill and the Administration's bill are far too coy on this point, calling allowances "a limited authorization to emit", hardly the stuff of daily commerce in goods and services. Off the record, we are told not to worry--that EPA would never revoke allowances for whimsical reasons, and that therefore, utilities and regulators should have every assurance that an allowance bought today will be usable sometime in the future. Frankly, we believe that such assurances must be put on the record, and that Congress should clearly state its intention that allowances cannot be confiscated except under truly extreme circumstances.

Second, we are concerned that the market for allowances will at times be very thin, a concern that S. 1630 shares as evidenced by its 2% hold back provision. As I have already discussed, under this legislation a workable market for allowances will be just as important to utility planners and regulators as a workable market for coal, or oil, or gas. Our concern with liquidity in the allowance trading market springs from the fact the S. 1630 and the Administration's proposal initially assign free allowances to certain utilities who may or may not need them. On this score, we believe the so-called "auction proposals" now circulating which would require all emitters of SO2 to participate in a periodic auction for all 8.9 million allowances may be an attractive alternative to avoid the prospect of never ending jurisdictional dispurtes between the EPA, the FERC, and the State commissions. NARUC is now giving careful consideration to how an auction-based trading system could be crafted to ensure workability, fairness, and reasonable prices for these essential commodities. We intend to focus our attention not only on the "100%" auction proposal, but also on alternatives in which various percentages of total allowances would be auctioned. We also intend to look at the benefits of auctions open to non-utility bidders such as brokers, fuel suppliers, and IPPs. With respect to the various auction proposals, Congress may wish to consider turning over the conduct of the auction to a more neutral Federal agency such as the Treasury, which is already experienced in such matters.

Third, we are concerned about the impact allowance trading will have on emerging competition in wholesale power markets. Many IPPs developers, none of whom will be assigned allowances under the legislation, have made known to us their view that they will be unable to compete fairly in the allowance markets, thereby restricting their ability to build fossil-based generating capacity. Inevitably, this issue will arise in the context of State-implemented bidding and other competitive procurement programs. State commissions that support greater participation by

IPPs in these programs, and who also wish to continue their support for qualifying cognerators (QFs) under the Public Utility Regulatory Policies Act (PURPA), will seek to develop ways to ensure that the lack of availability of allowances does not impede IPP and QF entry. In this regard, commissions in States with available allowances may require that a purchasing utility provide allowances to winning bidders, or State commissions may reserve a block of needed power for technologies with low emissions. In any event, an auction open to all bidders should go far to alleviate IPP concerns about access to the allowance market. Again, we are studying these proposals and urge full consideration by both Houses of the Congress, particularly those Members who would prefer that procompetitive electric supply policies not run aground on incompatible environmental regulations.

Fourth, to improve the operation of the trading system, Congress should consider full interstate trading in the early phases of the legislative program. Under the leading legislation, full interstate trading would only be allowed post-2000. If trading is such a good idea, why not exploit its advertised efficiencies as soon as possible? One of the uncertainties surrounding all trading proposals involves the prices at which allowances would trade on a per ton basis. Early interstate trading would help resolve this issue, thereby benefitting both market participants and regulators.

Fifth, if Congress accepts a percentage "holdback" of allowances in an EPA reserve along the lines of S. 1630, the allowances in the reserve should be made available at reasonable prices, and not at some arbitrary price floor. The best way to determine the price at which allowances in the reserve will trade is through an auction. The benefits of an auction, as opposed to a fixed $1500 per ton price, is that under an auction, the reserve allowances would actually trade in the market. This would be beneficial in two ways: first, utilities and IPPs would have some source other than owners of "affected units" to purchase allowances, and second, the owners of "affected units" whose allotments of allowances were reduced to create the reserve would have some assurance that EPA would be able to compensate them for the reduction through the auction proceeds.

On this point, we have serious doubts that the 2% set-aside in S. 1630 coupled with the $1500 price will have any other effect than to reduce liquidity in the allowance market. By establishing an artificially high price, the bill would in fact reduce available allowances by 2%, unless the price in the private market exceeded that level, in which case, the reserve would not be necessary. In reality, the 2% holdback serves no purpose other than to reduce emissions from "affected units" below the 1.2 lbs emission standard.

Sixth, Congress must ensure that any allowance trading system is implemented quickly and efficiently by EPA. In our view, EPA's involvement in the trading system should be essentially mechanical, meaning that the agency's role must be no more than to issue the allowances initially, act as a repository for reported allowances trades, reconcile the accounts of allowance buyers and sellers, and monitor actual emissions in light of allowance holdings. We respectfully and strongly submit that EPA should have no role in further "regulating" utility participation in the allowance market. Other issues concerning the price at which allowances are bought and sold, to whom and from whom they are transferred, what plants they are intended to support, what the costs of alternative control strategies are, and how costs should be recovered in rates, to name but a few, are the business of the utilities and their State regulatory commissions, and not the EPA. Rather, EPA should have no other role than to ensure that the mechanics of allowance trading work smoothly and predictably. In this regard, we believe that the legislation must contain a provision declaring that the bill does not preempt State utility regulation similar to that now written into the Draft Proposal now being circulated by the Chairman of the House Energy and Commerce Committee.

In conclusion, the NARUC reaffirms its support in principle for the establishment of a trading program as a means to reduce total compliance costs. In the days and weeks ahead, we will continue to analyze the leading proposals before the Congress to ensure that the are workable and compatible with the ways in which utilities are economically regulated by our members.

ENERGY POLICY IMPLICATIONS OF COST SHARING

I am a bit uncomfortable in addressing this issue for very obvious reasons. Just as the Congress is currently divided on regional lines on the issue of cost sharing and subsidies, the NARUC is similarly torn. Obviously, commissions from States which expect high compliance costs under the legislation would prefer that the bills be amended to spread their costs more broadly. Commissions from other States who will be relatively unaffected by the direct costs of the bills (but of course not the allowance trading system) object to cost sharing on the grounds that their ratepayers have already borne substantial costs to ensure their own relatively clean operations.

In conclusion, the NARUC greatly appreciates this opportunity to present its views on this important issue. We hope to continue to work with the Congress and the Administration, including EPA, as final legislation is crafted. We are particularly hopeful that as various alternative trading programs are developed, the congressional committees and the EPA consider how to ensure that the system is efficient and workable in light of utility regulation.

Indeed, once final legislation is enacted, we intend to continue to work with EPA in the implementation phase of the regulatory process, particularly with respect to the design and operation of regulations implementing the allowance trading program. In our view, implementation of this novel program will require a close working relationship between State regulatory commissions, the Federal Energy Regulatory Commission, and the EPA. To that end, we intend to approach EPA to fund a joint study of the relationship of emissions trading at the Federal level and State economic regulation of utilities. Specifically we plan to propose that EPA contract with the National Regulatory Research Institute (NRRI), NARUC's research arm, to conduct this necessary analysis. We urge the Congress to direct EPA to undertake this important work, particularly since the Agency is now contracting with others less familiar with State utility regulation to address these questions.

Thank you for you time and attention. I would be happy to answer any questions you might have.

Convention Floor Resolution No. 9

Resolution on Acid Rain and Emissions Trading Legislation

WHEREAS, Congress is now considering legislation proposed by the Administration to control acid rain precursor emissions from electric utilities; and

WHEREAS, The Administration's bill (S. 1490/H.R. 3030) proposes that utility emissions be capped after the year 2000, thereby requiring utilities seeking to add fossil-based generating capacity to acquire emission allowances from other utilities through the trading system established by the bill; and

WHEREAS, At its 1989 Summer Meeting, the National Association of Regulatory Utility Commissioners' (NARUC) Executive Committee adopted a resolution supporting equitable and cost-effective acid rain control legislation which is compatible with State regulation of the rates and services of electric utilities; and

WHEREAS, The Administration's proposed use of the 1985-87 years as the baseline for utility emissions is arbitrary and does not recognize aberrations that may have existed during this particular period and yields inequitable results; and

WHEREAS, There may be nothing inherently wrong with emissions trading, some trading proposals could lead to inequitable results; and

WHEREAS, In recent weeks, emissions trading plans have been criticized as being unworkable because utilities will not freely trade emissions allowances that they have created through their own control measures; and

WHEREAS, In response to this criticism, proposals have been made which preempt State regulation of utility involvement in the emissions trading system in order to "free up the market" by, inter alia, prohibiting State commissions from requiring that utilities "bank" their allowances to support their own future needs for growth in generating capacity, by requiring that State commissions permit utility shareholders to profit from the sale of allowances, and by suggesting that regulation of the prudence of allowance purchases and sales be in the hands of the Federal Energy Regulatory Commission (FERC); and

WHEREAS, Utility participation in any emissions trading market, and State regulation of that participation, will be motivated by the utility's legal obligation to provide reliable, cost-effective service now and in the future; now, therefore, be it

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its 101st Annual Convention in Boston, Massachusetts, hereby reaffirms its support for cost-effective and equitable legislation as contained in the Resolution on Acid Rain Legislative Proposals adopted on July 27, 1989, to control the emission of acid rain precursors from all sources, including nonutility emitters; and be it further

RESOLVED, That the NARUC is deeply concerned that the emissions trading provisions of the Administration's legislation as testified to by Environmental Protection Agency (EPA) and others fail to address the regulated status of utilities participating in the allowance market, and therefore may be unworkable in light of the obligation of utilities and State commissions to provide sufficient generating capacity for the future needs of consumers; and be it further

RESOLVED, That the NARUC Committee on Electricity is directed to promptly develop alternatives to the present emission allowance trading program which are consistent with and recognize the economic regulation of electric utilities; and be it further

RESOLVED, That the NARUC strongly opposes any legislative provisions which would preempt, prescribe or otherwise interfere with State regulation of utility participation in allowance trading markets; and be it further

RESOLVED, That the NARUC opposes the use of arbitrary base line years that fail to recognize aberrations that may have existed during that period, and supports providing for the possibility of deviating from the base time frame where circumstances so warrant.

Sponsored by the Committee on Electricity
Adopted November 15, 1989

The CHAIRMAN. Thank you very much, Mr. Badger.

Mr. Rosenberg, I want to see if I can understand how this trading program will work and if it will work properly.

Now the criticism, of course, is made that the realization is here that it will be an economic growth controller. Maybe I should not say it is a criticism. The trading program and cap, we are together on that, are we not?

Mr. ROSENBERG. That is the criticism. We do not believe that that is true. We think that the cap just establishes an environmental level that is feasible within which to live and the trading system is a way in which to do that at the lowest cost. We do not believe, however, that the levels that environmental protection must come at an economic cost, nor do we believe these numbers we have heard here today about 17 and 23 and 44 percent rates increases.

Our judgment is that on a national basis the overall cost of this bill is about $4 billion.

The CHAIRMAN. Well, let me stop you right there. In a clean state and not one of the super clean states but in a clean state like mine that has a lot of nuclear and has only, I think, one coal plant which uses a scrubber, come the year 2000 it has held to its 1985 to 1987 rates of emissions in sulfur; is that right? Do I understand that correctly?

Mr. ROSENBERG. That is correct. It would be held on a plant-by-plant basis. If there is a coal plant, it might have to reduce it. If there were a gas plant, there would be no requirement for a reduction. Really, the thing works on a case-by-case basis by plant, but the overall levels would not—

The CHAIRMAN. The point is how would a clean state go about getting additional electricity other than by buying?

Mr. ROSENBERG. First of all, it could fuel switch. You could use more gas than you have been using in the past, for example, for any state, for any facility.

The CHAIRMAN. What would you do about nuclear plants?

Mr. ROSENBERG. Nuclear plants do not have to clean up. There would be no requirement.

The CHAIRMAN. We are talking about future growth.

Mr. ROSENBERG. Well, in almost all states there is the opportunity if they have coal facilities to improve those coal facilities either by putting on new technologies, cleaning the coal or changing some of the coal to gas.

The CHAIRMAN. I say they are a clean state, and I think mine falls in this category. We have one coal plant, and it scrubs, and they can use this Wyoming coal. We have the twonuclear plants and some gas and that sort of thing. It would be very difficult for us to expand our capacity without buying credits, would it not?

Mr. ROSENBERG. Well, I assume that is true. It depends upon how efficient the scrubber is. But perhaps it sounds that way.

The CHAIRMAN. I mean, is that not reasonably typical within a lot of states in the southeast that do go to great extent to clean up?

Mr. ROSENBERG. There are many states in the southeast that use a lot of coal. The Southern Company, for example, would have rates that are not unlike the American Electric Power Company, and so I would not say that that is true from the southeast totally.

I would say that perhaps for Louisiana it is more difficult than it would be in other places. Let us assume for the moment that the cost of improving efficiency of existing plants is greater per ton than it might be somewhere else.

Under the trading system, you would have the choice either to reduce your own pollution controls or to go out into the national marketplace and find out who would be willing to sell these emission allowances at the lowest cost, and you would be unconstrained in negotiating that price.

The CHAIRMAN. The point I am making, though, is that in my state if you cannot get the allowances you cannot grow economically. Is that right?

Mr. ROSENBERG. Yes.

The CHAIRMAN. I mean as a practical matter.

Mr. TRIPP. Could I just refer you to section 405 (d) and (e) of the draft bill? That provides in a state like yours for 20 percent allowances above the baseline.

Senator FORD. Mr. Tripp, to which bill are you referring now?

Mr. TRIPP. 1630.

Senator FORD. The committee bill and not the administration bill?

Mr. TRIPP. The committee bill. As an environmentalist, I am not enamored of that section.

Senator FORD. That is the only section bought off for immunity, though.

Mr. TRIPP. You can burn more gas, which does not have SO_2 emissions. You can make energy efficiency investments. Furthermore, scrubber technology today allows for the removal of more than 90 percent of the SO_2 so that you can build a new plant today that removes burning 3 or 4 percent coal, which gets you down to .3 or .4 pounds of sulfur per million Btu, which is a third to a quarter of the 1.2 level, and the number of additional credits that you would have to get to build a huge new plant are minimal.

So my answer is I do not think that this bill at all inhibits economic growth.

The CHAIRMAN. Well, I am wondering, though, in those states that are going to have these credits to sell, it seems as though it would be an easy thing for the state to adopt a policy through its PUCs to say, yes, you can sell these but sell them in-state.

What do we do in any of this legislation to prevent that? Is that a problem, Mr. Badger?

Mr. BADGER. Well, Mr. Chairman, I think we should recognize that the utilities that provide service have a statutory obligation to provide a safe, adequate, reliable service, as do we as appointed officials in the state to ensure that that process that that process occurs.

I would respectfully suggest it would be irresponsible for a state commission not to first address the needs of all the plants for utility A or if we have seven utility companies in his state to see what requirements he may need in the future as well as members of the interstate system or members of a regional pool. There is an obligation that you have in place that you must recognize.

I have a Governor who is traveling all over this world, saying come to Maryland, bring your industry here, and I can assure you that my first obligation is going to be to make sure that the utilities in my state for which they have the statutory responsibilities are adequately protected to reasonably accommodate future growth.

The CHAIRMAN. Could we or should we legislate to prevent that?

Mr. ROSENBERG. I do not think so. I was also a chairman of a utility commission in Michigan, and I think that one of the goals of a commission would be to keep the utility rates down. To the extent that a company did not need its future growth allowances, they would be encouraged to sell them as away to keep the rates down.

In fact, the utility commission of Ohio, which probably has the most work to do under this bill, passed a resolution just a week ago where they said it would not be the policy of this commission to encourage utilities to hoard the permits earned but, rather, to best utilize them to reduce the overall cost of complying with clean air requirements and ensure that Ohioans maximize the economic benefits from permits earned during the limited time window in which the permits will be tradable and of economic benefit.

It is our sense that this would reflect a progressive way of looking at the problem. Let us look at our planning requirements. Let us see what we need. To the extent that it is possible to overcontrol beyond our needs and then have allowances to sell to the folks in Louisiana, that has a rate implication recognized by the State of Ohio and encouraged by them.

There are 9 million permits out there roughly. A typical new plant might require 5,000 or so. It would not require that much. We would estimate that the cost of acquiring their permits would be in the 5 percent range if you could not develop it yourself; that is, the electric power cost would not increase more than 5 percent.

So with the scope of the marketplace being 9 million permits and a new plant that will burn coal, particularly low sulfur western coal that might be appropriate in Louisiana, you are talking about a very, very small percentage of that market that needs to be accessed.

In response to both the House and Senate committees' concern about this, we encourage the Senate committee to develop a proposal for EPA to be the seller of last resort, so that if a developer of a plant, whether it be an independent power producer, a municipality or a public or private power producer in Louisiana, went into the marketplace and was unable to acquire permits, there is a provision of a 200,000 setaside, if you will, that would enable EPA to recapture permits from those that have it and present it to people in Louisiana who need 3,000 or 4,000 to build a new plant.

The CHAIRMAN. Tell me about this marketplace. I have heard the words ""marketplace" and "banking". How would that work?

Mr. ROSENBERG. Well, let us assume the requirement to operate the plant was 50,000 permits.

The CHAIRMAN. You have some permits, and you are ready to sell.

Mr. ROSENBERG. If in fact you would run the plant at 25,000 permits and you have some left over, you can treat that as money in the bank. You can either leave it for future use by that particular facility on an annual basis, or you could sell that on an annual basis to another utility.

The CHAIRMAN. What I am getting at is how do you sell? Do you foresee that each of the utilities in the country would sort of advertise in the New York Times, or do you foresee a bank growing up under this so that you can maybe sell to the bank before you actually trade it with somebody?

Mr. ROSENBERG. We would foresee that there would be a market created with the secondary marketmakers like other commodities. It would not be an EPA function to participate. All we would do is keep track of A sold it to B, now B has it, and we would just kind of maintain the accounts. At the end of the year each utility has to come to EPA with the necessary permits to cover their obligations.

We would expect that the free market would establish a commodity exchange along these lines. We would monitor that, but I think it was part of the goals of the Council of Economic Advisers not to have EPA in the middle, which would prevent the market from working.

The CHAIRMAN. Let me ask Mr. Badger respond to this on the market. Then we will come to you, Mr. Tripp.

Mr. BADGER. I should tell you we are not convinced that this market mechanism would work for the reasons I outlined.

Mr. Rosenberg has mentioned the Ohio resolution. I should tell you the Ohio resolution was really undertaken to address those who were urging that we can never have any state or any utility retain a credit; therefore, we must amend this bill to be sure it never occurs. So this was a reaction from a state to say we will not retain those.

The CHAIRMAN. That would not bind future agencies, would it?

Mr. BADGER. I was just about to lead you there, sir. With all due respect to my colleagues in Ohio, I should point out to the committee that the actions of one commission cannot bind future commissioners to the way the bills are now structured.

I cannot imagine that a utility company in the State of Ohio will undertake excess control investments on a promise that somewhere down the line they may receive cash and a profit on that allowance from another utility company located in this Nation. I say that because there is nothing in these bills that require an up-front payment for these allowances.

In addition to that——

The CHAIRMAN. By the way, let me interrupt to ask who gets the money? Would the ratepayers get it, or would the utility get it? Is there anything in the bill about that?

Mr. BADGER. That is another issue that I see is in one of your questions. I think that the matter would be subject to an evidentiary process. We should keep in mind that the very plants that give rise to these credits have been financed in their entirety by ratepayers.

So I think it is an open question as to whether any particular commission would intend to flow all of that back to the ratepayers who financed it initially or as an incentive to stimulate the marketplace would have a sharing concept.

Just finally finishing the question about the contract, keep in mind that the difficulty of what is authored by Ohio, which I certainly would support—none of us would retain those if we did not have to. But if you have a situation as you do in this legislation that at any time EPA can revoke, rescind or modify those allowances, we have great difficulty understanding how two people can execute a contract to transfer something that essentially they no longer have value at the stroke of a pen. We see difficulties with that.

The CHAIRMAN. How long would it take a utility to plan and execute construction to put on a scrubber or clean up its emissions in order to earn this? How long does it typically take?

Mr. DOWD. Well, if we were to install a scrubber in order to generate overcontrol, you are talking about a lead time of at least 4 years. Now one thing I think you need to bear——

The CHAIRMAN. Just a minute. I wanted to get that, because I interrupted Mr. Tripp. All right, do we agree about 4 years?

What I am wondering is what Mr. Badger alluded to, and maybe you would like to respond to this, Mr. Tripp, how can you get some certainty with this utility that would have to—first of all it has got to spend some money to earn the credits. It has got to take four years.

He is not going to know—or, will he know how the PUC is going to treat that, whether they get to rate-base it—I mean, whether they get to flow it back to the ratepayers or whether they can use it for growth or for dividends or whatever—and then he is not going to know what he is going to be able to sell it for, is he?

Mr. TRIPP. Well, I think my answer to that, senator, is the contract process. Let us take a very simple example. Two utilities, now, are burning coal, emitting 3 pounds of sulfur per million Btu. In Phase I they have to go down to 2.5.

Let us say, under this example, for one utility it would cost $400 a ton to do that, for another utility $600 a ton to do that. For the utility that can do it for $400 a ton, it can go down to two pounds of SO_2 per million BTU for $400 a ton.

So one plant could go from three to two at $400 a ton all the way, the other plant could stay at three, and it would have cost $600 a ton to do that. So for 800 tons you accomplish the same amount that you would, with a trading program, that it would cost $1,000 a ton if they each had to do it individually.

Now, how it would work, utility A that can do it for $400 a ton would go to utility B and say, let us enter into a contract. I will promise to give you these credits, at some point in the time I will sell them to you for whatever price they want a contract for under this arrangement.

So at the beginning of Phase 1, you can go to EPA—you are still emitting 3 pounds per million BTU, but you go with the requisite credits under this program. Meanwhile, the seller of the credits has gone down to two. That is cost effective, because the two utilities together can reduce their total loadings of SO_2 by the same amount that they are supposed to do individually at less cost, and that is why it is a good program.

The CHAIRMAN. By the way, do you earn credits before the year 2000?

Mr. ROSENBERG. Yes, you do, sir.

The **Chairman**. Let us say the bill goes into effect in 1990. You clean up by 1994, and you do not have a market or you want to hold them and you hold them from 1994 to the year 2000. Do you get 6 years of credits times the number of things which you can sell?

Mr. **Rosenberg**. Yes, sir.

The **Chairman**. Even though you have not given somebody else that provision?

Mr. **Rosenberg**. That is right. To the extent that you have not turned them in to EPA at the end of the year, because you used them yourself, you can use them in the future. There is no limitation on that.

The **Chairman**. They are more or less credits per year?

Mr. **Rosenberg**. That is right, and that is why we call that the banking provision, so that if you accumulate credits that you have not used that year, you can retain them for use in the future year, or sell them as you wish.

The **Chairman**. So you hold that for the year 2000 and then in the year 2000 you dirty back up to your limit but you still have the 6 years of credits you can sell.

Mr. **Rosenberg**. That is right, or use to offset the increased emissions that you yourself are developing.

Mr. **Dowd**. Mr. Chairman, might I provide the Committee with the utility perspective on this and explain, and I think ultimately we get to your basic question of what there is to sell to the growth areas, the Southwest and Florida and so forth.

But on the AEP system we will be required to achieve very, very substantial emission reductions and we would propose in Phase 1 to scrub a number of our large units and to overcontrol to the maximum extent possible, but we would apply that overcontrol to the protection or the sheltering of the smaller units on our system in Phase I.

These are units that were built in the 1950's and as to which it would not be economic to retrofit with scrubbers units that have cycloned or wet bottom borders, as to which it would be very difficult to find a low-sulfur coal that would be burnable in those boilers without creating an ash fusion problem.

So while we could generate a very substantial amount of overcontrol in Phase I, that overcontrol would be used to protect these older units, as to which compliance would be extremely difficult, if not impossible.

Now, when we get to Phase II, we do not have much in the way of overcontrol left. If we were to go out and deliberately overcontrol for the sole purpose of providing emission allowances to the Southwest or to Florida, the first thing we would do in terms of marginal cost is to switch fuel at one of our major West Virginia plants.

Now, please bear in mind what that means in human terms. That means miner layoffs in the northern West Virginia panhandle, and why we would be doing that? We would be doing that in order to generate allowances to sell solely for the purpose of enabling the continuation of growth in the high-growth areas of the country.

Now, if our Public Service Commission directs us to do that, we will do it, but I suspect that overcontrol of that nature is not going to be well-received by the political regulatory communities in which we operate, and that should be borne in mind.

The CHAIRMAN. Obviously, I have a lot more questions. I do not want to consume all the time.

Ms. STUNTZ. Mr. Chairman, if I could just put my two cents worth in on this, I think Mr. Dowd raised one significant point. I am afraid there is a perception this morning that utilities will control precisely to the limit set in the bill and that any overcontrol beyond that would be done only to send allowances somewhere else.

I think that if you look at the technology, that is not reality. New technology will emerge if you are going to have to meet a 1.2 standard. If you are going to have to scrub a plant, new scrubbers will bring you way down to .3 or .4. We have heard discussion about this new technology this morning.

So whether or not you use the surplus allowances thereby created for other places on your system, thereby minimizing the cost on your system by doing that, or whether the value of allowances is such that you can sell them for even more than it costs you to reduce to that next level of control, which in the end will benefit your ratepayers to do that, I want to rebut the perception that the only reason one would ever overcontrol is solely to put allowances somewhere else, because that is not the way the technology will work.

Mr. DOWD. Mr. Chairman, we will overcontrol, as I indicated, our units that are susceptible of scrubber retrofits, we will bring them down to .3 pounds. Now, if that is not overcontrol, I do not know what is. But that overcontrol will be used to protect our old units.

I do not disagree at all with what Mrs. Stuntz says, but in our situation—and I am not sure that we are a typical—much of that overcontrol is going to be applied on our own system to protect units that otherwise would have to be shut down.

Senator BUMPERS. You can do that indefinitely, can you not, Mr. Dowd? You can do that past the year 2000, can you not?

In other words, if your plant—if you get a plant down to .30, you can take that allowance and use it on a dirtier plant as long as you want to?

Mr. DOWD. No. We use a large part of the allowance when Phase II bites. For example, we overcontrol——

Senator BUMPERS. I know you lose the allowance, but to such extent that the allowance is there, you can still use it, can you not?

Mr. DOWD. To the extent that we are controlling below 1.2, after the Phase II deadline, yes, that is correct.

Senator BUMPERS. So if you have two clean plants at .30 and you have got one dirty one, say at 1.7, you can operate that plant forever at 1.7 rather than 1.2, is that not true? This bill does not require every unit in the country by the year 2000 to be at 1.2, that is my point.

Mr. DOWD. That is correct.

Mr. ROSENBERG. The reason that that is good policy is that it will probably—it will only happen that way, senator, if the aggregate cost of control is lower by doing it that way, and what we are attempting to do here is to reduce the impact on utility rates and on the economy by giving that option.

Most of the trading will in fact be intra-utility, and most of the trading will in fact be intrastate, and the case that you mentioned, Senator Johnston, was, I think, an anomaly where a state would have not the opportunity, internally, to do most of the fuel switching or technology improvement or conservation internally.

The CHAIRMAN. Let me just read one thing, then I will turn it over to Senator McClure: a paragraph from a letter from the Southeastern Association of Regulatory Utility Commissioners which states that:

> In particular, tonnage caps as contained in the Administration's bills, or required tonnage reductions from a historical base year, would severely penalize growth states like those in the Southeast.
>
> The tonnage caps in H.R. 3030 and S. 1490, along with market-based allowance programs, would leave a core group of higher emission rate, primarily midwestern states, with allowances to sell.
>
> At the same time, clean and growing states like those in the Southeast would be required to pay premium prices for the obligation to serve increasing customer bases.

With that, I will turn it over to Senator McClure.

Senator MCCLURE. Thank you very much, Mr. Chairman.

I want to shift gears a little bit, but before getting into specific areas, Mr. Rosenberg, I want to understand one of the charts you used. It is not explained in your statement.

I refer to the chart on "Clean environment does not mean less economic growth." I am not quarreling with that chart. I want to know what it means.

You show electricity sales of 76 percent. How is that measured? Is that in units or in dollars?

Mr. ROSENBERG. I think it is kilowatt hours, actually.

Senator MCCLURE. Are you sure of that answer?

Mr. ROSENBERG. I am not. I can get that.

Senator MCCLURE. Does any one of your army behind you know the answer to that question?

Mr. BRENNER. What we tried to do there is create an index. What we have done is normalized everything to an index.

Senator MCCLURE. I want to know what that normalized index is. Is that in dollars or kilowatts?

Mr. BRENNER. The way you measure sales is in either kilowatt hours or in dollars. In this case, we are showing the increase in kilowatt hours sold.

Senator MCCLURE. That is kilowatt hours on electricity sales?

Mr. BRENNER. Right.

Senator MCCLURE. And GNP, how is that measured?

Mr. BRENNER. GNP is normally measured in dollars, and that is how we did it for this chart.

Senator MCCLURE. Are they adjusted dollars, or inflated dollars?

Mr. BRENNER. Adjusted dollars.

Senator MCCLURE. Adjusted to what base?

Mr. BRENNER. They were all adjusted to the same year. I believe it was 1987 dollars.

Senator MCCLURE. 1987 dollars. The next line I cannot see on my chart. Coal use. Is that in dollars or in tons?

Mr. BRENNER. Tons.

Senator **McClure**. Tons?

Mr. **Brenner**. Yes, sir.

Senator **McClure**. And the emission? What is that?

Mr. **Brenner**. Emissions is also in tons.

Senator **McClure**. Okay. Thank you very much.

The **Chairman**. May I interrupt just a second? Staff tells me something and I do not want the impression to get out, and the answer may have given the wrong impression. My question was, if you clean up by 1994 can you bank those and keep those, even though you do not use them?

As I understand it, you can do that only if you are one of 107 plants. If you are in a clean state you cannot do that, even though you clean up.

Mr. **Rosenberg**. Senator, you can. The 107 is the minimum that has to be in the system. If another plant wants to come into the system, they can register, establish the baseline and get credit as well.

The **Chairman**. Say that again.

Mr. **Rosenberg**. The 107 is required, but if you wanted to start the cleaning of another plant prior to that time, say the 108th plant, you can register that with the program and get the credits, so other plants can come in—can opt into the system.

The **Chairman**. That is only in the President's bill. That is not in the EPW bill. Is that correct?

Mr. **Brenner**. The EPW bill is not clear on that point, and it is ambiguous, and the best reading is probably that you would not be able to do it under the EPW bill.

The **Chairman**. If you cannot do it, you cannot get the credit, then you would be foolish to go spend the money and clean up before the year 2000, is that not right?

Mr. **Brenner**. Well, for example you may decide that if you contract for lower sulfur coal before 2000 it is cheaper, you can get a better deal on it, and you may decide to do it anyway, but it certainly is a disincentive compared to the case as in the Administration bill, where you could bank those allowances and use them later.

Senator **Wallop**. Could I just ask one thing, is there not an option for states to opt to not be clean states and gather the credits? Can you not opt out of the Clean State program and gather the credits and then operate normally until 2000?

Mr. **Brenner**. Senator Wallop, the Clean States provision is not in the Administration bill, it is only in the Senate bill, and it is not our reading of it that you could opt out of the Clean States program, and we have identified a number of states that probably would be better off being out of the Clean States program, yours being one of them.

Senator **Wallop**. That is a strange thing to do to a state, is to ask not to be considered clean—but as you read it, you cannot opt out. Is that right?

Mr. **Brenner**. That is my understanding of it, and the reason it is better for some states like New Mexico and Wyoming is that if you were not included in the Clean States provision you would be included in the provision that gives you an extra 20 percent of allowances for your clean units. That is far more beneficial to you than the requirements of the Clean States provision.

Mr. **Rosenberg**. And we very much do not support that Clean States provision, because there are many clean states like Louisiana that are not clean because they scrub coal, and they should not be discriminated against.

Senator **Rockefeller**. Senator McClure, can I just put one question in?

Does it strike you gentlemen as interesting, number one, and, number two, fair that, for example, Texas which is among the top emitters of both NO_x and sulphur dioxides is totally untouched by all of this because it happens to come from oil refineries and not from power plants? Does that strike you as either correct in fair or fair in principle?

Mr. **Rosenberg**. Well, there are many things that Texas has to do in the air toxics portion of the bill that are very substantial. We did an analysis that assessed how much of the cost would be borne by the dirtiest states. I have a chart I want to show you, if you would like to see it, and whereas the five states with the most emissions had in 1980 50 percent of the emissions, they are indeed required under this bill to reduce 65 percent to get 65 percent of the reductions.

However, because the reductions in those states are less expensive per ton, they would only get 50 percent of the costs of reductions so that even in the nine states that have the greatest amount of obligations under the bill, the nine states with the greatest SO_2, their proportion of costs are about equal to what the total lowering of emissions was.

From a rate point of view, the five hardest hit states start out with approximately a six cents per kilowatt hour rate in 1987. That is about 10 percent lower than the national average.

Their rate increase under the bill in these five states is about three-tenths of 1 cent a kilowatt hour, or 5 percent on the average. The rate increase in the other parts would be about 1 or 2 percent increase, but when it was all done, the five hardest hit states would still have average rates that were lower than the national average.

Senator **Rockefeller**. Senator McClure, I apologize to you, but that was unfair of me, but I have to go meet the Vice President, and so I thought that would be excusable.

I would simply point out for the record that——

Senator **Ford**. Meet who?

Senator **Rockefeller**. The Vice President. I thought that would gain me credibility with Senator McClure. [Laughter.]

Senator **McClure**. You did indeed. I am sorry it cost you so much elsewhere. [Laughter.]

Senator **Rockefeller**. But, Mr. Rosenberg, you will admit that what you are talking about, this so-called cost in the Midwest, has nothing to do with unemployment. It does not take into account rail rates or the higher cost of low sulphur coal?

Mr. **Rosenberg**. That is correct.

Mr. **Badger**. Senator, if I could just repeat what I said earlier, as far as the regulatory commissioners of the country, we share that concern and believe that industrial emitters should come under the umbrella of this bill.

It is estimated there are 10,000 of them and they are contributing one third of the SO_2 emissions.

We, as I said before, we recognize the difficulty of trying—for EPA to try to administer that quantity of emitters, but there may be some merit, at least, to having size threshold facility included in this legislation.

Mr. ROSENBERG. When we discuss the air toxics and non-attainment provisions tomorrow, I think you will see how heavily, in fact, the industrial emitters in the oil industry and the other industries are, in fact, covered by the bill.

That is one of the reasons why we felt that if we could resolve the issue of SO_2 on the utility sector and do it in an equitable way in the context of a total clean air program that that made sense.

Senator MCCLURE. I am fascinated by this idea of what kind of a market is going to develop in the exchange of credits. I think those of us who have elected not to run for reelection have a great growing opportunity out there. I can just see it now. The futures market on emissions credits 18 years from now, what is that contract worth? And I am going to find a way to make that worthwhile for some, maybe myself. [Laughter.]

For example, a utility building a new plant or making a decision on a new plant is going to try to cover that plant for the remaining useful life of the plant. That might be 15 years. Let us just pick a number or 10 years, and in buying credits he is going to want to cover each year of the operation of that plant as is a person with a credit going to obligate their credits for the next 20 years?

Mr. ROSENBERG. They certainly could, and that utility has the same problem on coal and in some cases they may lock up the coal 100 percent to their needs over the duration of the operation or they may have some contract coal and some spot coal and perhaps lock up 50 percent of the coal and plan to buy 50 percent on the open market.

We would expect that the utilities would approach this requirement precisely the same way they approach the coal requirement. They do not hoard coal, they would not hoard these. They may buy things on long-term contracts. They may negotiate short-term contracts. That is how the market will work, to reduce the cost to the ratepayer.

Senator MCCLURE. People look at things like hoarding. That is a loaded term around this town. It depends upon who looks at that as to whether that is hoarding or not.

I remember not long ago when coal companies that had long-term contracts and commitments said they were hoarding coal because they had federal leases to cover those commitments, and so some people—even some on this committee—were condemnatory of that practice and called it hoarding. And so, I guess it depends.

Mr. ROSENBERG. There is another point on allowance availability that should be emphasized here. Beginning in about 2010 many of the plants that Mr. Dowd talked about, the old 1950s plants, will retire because they are obsolete environmentally and economically, and they will be replaced by newer plants that will operate at a much lower rate than the 1.2 pounds that the older plants are permitted to operate under, and that will free up emissions and particularly if the Department of Energy's clean coal technology works out as well, the program works out as well as we hope.

And so, you will be replacing by retiring the older, dirtier plants, you will be making available two, three, or four times as much allowances in terms of capacity that were required from the old plant that now can be employed by new technology.

Senator McCLURE. My time is limited, as is every member of the panel on your side and on our side as well. I want to shift away because there are other issues than the credits issue and the marketing and credits.

Ms. Stuntz, there does not appear to me to be any economic justification or at least I have not seen one for the trading ratios of one and one half NO_x for one SO_x. That is contained in section 403(c). Can you provide us with the technical basis for such a ratio?

Ms. STUNTZ. I would happy to, and I think your question assumes the answer. It is largely a function of what we understand about the contribution of NO_x to acid rain formation versus the contribution of SO_x. Probably Mr. Brenner or Mr. Rosenberg could give you the physical details on that better than I can, but that is the basis for that trading ratio.

Senator McCLURE. I would like to have whichever. Do you, Dr. Mahoney, or you, Mr. Rosenberg, have the scientific justification for that ratio?

Dr. MAHONEY. Senator McClure, the one and a half to one ratio is approximately the ratio as far as the basic substances are concerned.

That would mean an equivalent amount of hydrogen ion with the basic acid measure would be deposited. Because of the differences in molecular weight, one and one half tons of nitrogen oxide would produce as much acidity as approximately one ton of sulphur oxide. That was behind the general consideration.

The exact proportion could have been stated, but it would have been futile, in fact. There would have been no point in trying to use the exact molecular rate ratio, which would have been slightly different, because any attempt to interrelate also has to consider whether the sheer acid forming potential is the only aspect or whether there are other aspects as well.

My prepared statement, in fact, deals somewhat with the matter. We recognize there are some important considerations about nitrogen oxide controls that are different than the simple ratioing of acidity, and I think it is fair to say no one has a universal answer to that. We debated that a good deal in the last several months, and even as a technical matter the issues come down to the fact that the nitrogen species has different impacts, some actually even beneficial, but mostly still adverse.

Nitrogen is, after all, a fertilizer and that by itself can be good or bad. But, in addition to the deposition part, there is yet another consideration about nitrogen. Nitrogen oxides are involved in the formation of ozone in the atmosphere, and we know there are substantial adverse effects from ozone.

Anyway, the bottom line of all of that is that in a great deal of discussion, there was no agreed technical basis to pick something other than the approximate molecular weight ratio at this time given what we know.

I think technically we believe it is laudable to make this linkage because it does provide certain flexibility and it also provides the understanding that both of these pollutants deserve control.

Senator McClure. All right, if I can boil that down to a shorter one, you do not know whether that is right or not, but it is the best you can do.

Dr. Mahoney. Yes, sir. [Laughter.]

Senator McClure. In crafting the allowance and permit provisions in the acid rain titles of both S. 1490 and S. 1630 did the administration give consideration to the real world impact that this marketing and trading system between the utilities would have on electric reliability in various regions of the country?

Ms. Stuntz. Sir, yes, we did, and I think it is important to note that this concept is not quite as novel as perhaps Commissioner Badger would suggest. There exists now, and I think we will talk about it tomorrow in greater detail, an offset program for pollutants, particularly volatile organic compounds and hydrocarbons, that basically entails the same type of emissions trading. If you are going to expand a facility or build a new facility in a non-attainment area right now one of the ways you can accommodate the growth is to go out and find someone else who is willing to reduce emissions or relocate.

So, we have had some experience with this proposal. We think that it will not affect reliability. We think, if anything, because of the capital investments that clearly are going to be required in these facilities to meet these guidelines, it will be very important to increase the efficiency of these facilities to maintain the output in order to obtain a return on that capital investment. Assuming we can get the proper incentives in place in time for effective, innovative clean coal technologies, we do not believe there will be an adverse effect on electricity reliability.

Senator McClure. Have you analyzed the effect that it will have on imports of energy?

Ms. Stuntz. We have done some preliminary analysis on that. I believe it is addressed somewhat in some of the specific questions and answers that you asked.

We think that there may be some increase in electricity imports from Canada. There may be some increase in natural gas imports, but it is difficult to determine because we do not know what specific compliance strategies will be chosen. We do not know some of the macroeconomic effects such as how much natural gas prices will increase as a result of the increased demand for natural gas resulting from this bill.

Price increases may, in turn, elicit more domestic supplies. We have given you some estimates in my questions for the record. There are also capacity constraints that must be taken under consideration, both in terms of natural gas pipelines and electricity transmissions systems, so one has to look at the question over time.

Senator McClure. Mr. Badger.

Mr. Badger. Senator, if I might just add to the point that you asked, I think we have a very good example right in our own state. We have had Calvert Cliffs which in about another three months will have been closed down for almost one year.

If we were under the provisions of this bill right now and if we did not have emissions allowances, generated and banked, I should tell you we do not anticipate we would have that many. Virtually we would be compelled to ration electricity because we depended, we have depended on coal to replace that power in purchasing through other power pools. So, it is these types of uncertainties.

It is the need to have insurance policies that state commissions and utilities believe are necessary to protect from these kind of unforeseen events or forced outages. It is those kind of uncertainties that are going to lead utilities to recommend and utility commissions to be sure that that bank contains adequate allowances to operate in the case of emergency.

In that regard, as I noted earlier, we would strongly urge an amendment to direct this type of unforeseen event be included in any legislation.

Senator McCLURE. Mr. Tripp.

Mr. TRIPP. Well, let me say, first of all, I do not believe this bill is going to have any adverse effect on the reliability of power.

One recent example was Pepco, which is a Maryland utility, has just recently entered into a 20-year bulk power agreement with Ohio Edison, and part of that agreement is not only to import power, but for Pepco to pay its pro-rata share of the acid rain controls in Ohio, and I think that is a typical example of what is going to happen.

The reliability of service will be the same. We will just see broader contracts to cover these costs, and as far as oil imports, I think the effect of the cap with trading will be favorable because I think the next effect of this bill is going to be to encourage and foster and facilitate energy efficiency investments that should be made anyhow on straight financial and economic grounds. It will foster that, and that will lead to a net reduction in imports of oil.

Mr. DOWD. Senator, may I add to the answer to these questions regarding the importation of electricity as a result of the cap?

The province of Ontario last year instituted its own SO_2 emissions cap and as they approached September or October, they saw that there was a serious problem. They were not going to meet their cap. As a consequence, they have been buying very substantial amounts of electricity from the American Electric Power system.

Now, there is an irony in all of this and there is also, I think, a lesson insofar as the cap is concerned.

Senator McCLURE. I think I have used my time. I will yield although I have some other questions, Mr. Chairman. Thank you.

The CHAIRMAN. I would say to all members we would like to submit some questions in writing because we will not be able to cover them all.

Senator Bumpers.

Senator BUMPERS. Thank you, Mr. Chairman.

Mr. Rosenberg, as I said in my opening statement, my view on this is necessarily parochial in my state because we have spent such tremendous sums of money to do exactly what this bill requires us to do, and we are one of the clean states.

Now, if the 20 percent allowance will not take care of us—let me give you an illustration. If we are burning in one of our units, for example, .50—if our emissions are .50, a 20 percent allowance would allow us to go to .60. Do you agree?

Mr. **Rosenberg**. Yes.

Senator **Bumpers**. Now, because of this 1985 provision, which really presents us—I mean, it was an aberration; I cannot explain it to you. But in that particular case, let us assume that that plant was operating at .40 in 1985, but since that time, because we got super-clean coal in, the plant is normally going to run around .70 or .80.

This bill requires us to spend, on two units, $250 million dollars each, a half-billion dollars on one two-unit plant in order to get back to that 1985 emission. Does that, just off the top of your head, sound fair to you?

Mr. **Rosenberg**. Well, there are ongoing discussions on this very issue. We have acknowledged that the 1985—1985 to 1987 capacity calculation and the 1985 rate, particularly the capacity calculation, does create anomalies in a situation like you mentioned. And that is the one part of the bill that really we would like to take some comments on.

And we are talking with the House Committee and the Senate Committee; that has not been addressed. And recognize that there are some equity questions here because of unique circumstances relating to 1985, like the one you just mentioned.

So, I would say that we are looking for some fixes on this. Perhaps we can involve you and your staff on this.

Senator **Bumpers**. I appreciate that very much. The fact that you're open-minded on it gives me considerable comfort.

The **Chairman**. Senator Bumpers, would you allow me to interrupt just to say this?

This panel is very good, and I think we probably have more members than we have time this morning, that is, if we are going to terminate at a reasonable hour.

I wonder if the panel could come back for a short period of time at 2:00 to continue so that all members could get questions in. Is there anyone who could not? Could you all come back at 2:00?

Senator **Ford**. What does that mean, Mr. Chairman? Those of us that have been sitting here since 9:30 and acquiesced on statements are going to be cut off?

The **Chairman**. No, it means that if Senator Bumpers will be reasonably short——

Senator **Ford**. I am next——

The **Chairman**. I think you are next.

Senator **Ford**. I was watching how you were cutting this end off over here.

The **Chairman**. No, I want to be sure that you are not cutoff.

Senator **McConnell**. Mr. Chairman, in other words, if we want to finish now, and we are already here, we can do that. And then we will come back to the others.

The **Chairman**. Absolutely.

Senator **Bumpers**. If I may go ahead just for the purposes of the record, because you have given me the precise answer that I wanted, Mr. Rosenberg, but just to point out the inequity in this thing.

A plant in Ohio, for example, who is at 3 pounds or, we will say roughly six times as much as an Arkansas plant, for their half-billion-dollar investment in a plant, they build up tremendous allowances and guarantee room for economic growth in the future. We spend a half-dollar to scrub a very infinitesimal amount of coal and we wind up with no allowances. So you can see why I am squealing like a pig under a gate.

This is just simply totally unacceptable. But that is the principal point I wanted to make.

Dr. Mahoney, I wanted to ask you what do your studies show way out into the future if we reach this roughly 9 billion tons a year, if we reach the goal of 19—I am sorry, the year 2000, if we cut our emissions in half by then—we cut 10 million tons—I am sorry. We cut 10 million tons of emissions by the year 2000, then what happens to these lakes and forests? Can you tell us that? Are we going to see juvenation of the brook trout and the Adirondacks and so on?

Dr. **Mahoney**. Senator Bumpers, if the reduction is achieved by the year 2000, which is kind of a common feature in all of the bills that you are considering, what we expect, I think it is fair to say, is this. In the Northeast, generally, as a response to the lower amount of sulfur oxides and sulfates entering the soils and watersheds, the lakes and streams will begin demonstrating lower amounts of such sulfuroxides and sulfates quite quickly within a few years in the Northeast. The reason for that is that the Northeast soil snow are virtually saturated with the sulfur they can contain. What comes in goes right out again.

Now, acidity is different than sulfur concentration and no one measure controls what happens to the fish, for example. So our best analyses now suggest that the acidity improvements will take a few decades. As I testified before, and as is in some of our reports now, in the period of approximately 30 to 50 years, we would see about one-half of the lakes in the most impacted northeastern area, the Adirondacks, for example, recover.

Now, to try to get a sense of interpretation, we could, look at that as a half-empty or a half-full type of statement. On the one hand, we can say that is going to take so long, we can take our time about getting going with the controls because we will not see the improvement for some time anyway.

On exactly the opposite hand, you could say that it is going to take that long; we have to get started at this process sometime. We would not as scientists try to argue that perspective, but we can tell you that our best projection is those are the times that it would take to achieve some improvement.

If you would like, I will say a word about the forest. I know time is limited, and so I do not want to go on for too long.

Senator **Bumpers**. If you would, just briefly.

Dr. **Mahoney**. On the forest side, it is a much more chancy area. We do not have data that suggests profound impacts now with the exception of the concerns we have about the spruce forest at the mountain top locations, as I think has fairly commonly been discussed. We do have a very long-term concern about the build-up of acids in forest soils which can liberate aluminum and other metals, and can have a very long-term impact on forest decline, although that is something we cannot measure at this time.

In the forest situation, we would expect to see a reduction of this mountaintop stress and, insofar as the acid rain is a major contributor to the mountaintop forest decline, we would expect to see that begin to improve reasonably rapidly, in the order of, let me say, 10 years or so. Nothing happens just overnight.

The result of this is that when we look at the forest situation, we expect improvement. It will be more difficult to measure that because the cases of damage are in fact fairly limited—important, but limited, and we know many stresses play a role in this.

And so, I think our scientific view, just as the bottom line is we will expect improvement and it is very important insurance to move in that direction, but I do not think wewill see any profound changes in the next one or two decades after the controls.

Senator BUMPERS. Mr. Rosenberg, let me ask you this question and, if you can, give me a brief answer.

This bill, as you know, provides for a 2-percent reserve to be dispensed, I guess, at the largess of the administrator. And you can sell emissions at $1,500 a ton, as I understand it, that 2-percent reserve.

The independent power producers feel really put upon by this bill because they feel they will never get allowance and therefore never be able to be a player if this bill goes into effect, but if that were raised to 5 percent, they might have a shot. Your reaction to that?

Mr. ROSENBERG. Well, the reserve only will occur if the market does not work, that the reserve allows the administrator to tap the market—to tap the allowances of companies that have the allowances for the benefit of new developing plants that are unable, after they try, to participate in the market.

It is our position that that will not happen and that this is a failsafe issue. We have had conversations with the power producers and really this has been developed by Dr. Schmalensee at the Council of Economic Advisors, and they are very comfortable that under any scenario that can be imagined by them, that the 2 percent is adequate.

We must in fairness give to the companies that have to do a tremendous amount of work some certainty as to what they can work with. And we felt that 2 percent would be somewhat of a noise level, but you get to 5 percent and it could impact the safety planning questions.

We have had conversations with them and do believe that we have presented our data. They have not been able to say that 2 percent is not enough; they are just concerned about the issue. We are concerned about the issue. The Department of Justice would be very concerned in an antitrust sense if there was any concerted action to keep the independent power producers or any other developer of plants out. We think they perform a very important function.

It is our sense that the 2 percent is more than adequate and that what is really key is that there be a robust trading system, which we will dedicate our efforts to achieve.

Senator Bumpers. That brings me to my next question to Mr. Badger.

As you have—and I want to make one point, just to make this point, and that is, as I understand this, between now and 1995, all of these plants in the Midwest, most of them in the Midwest, the 107, as a particular system goes below 2.5 pounds per thousand, can they bank that allowance that they gain forever? I mean, can they keep that allowance for any time in the future and use it?

Mr. Rosenberg. Yes.

Senator Bumpers. So, if they put scrubbers on between now, for example—let us assume they are at whatever, anything above 2.5. Any amount they go below 2.5 between now and 1995 is a bankable allowance, is it not?

Mr. Rosenberg. Well, that was the question that was asked of Rob Brenner. In the administration's bill it was very clear. In the Senate bill it needs some clarification to assure that that happens. After 1995, I think it is pretty clear in both bills that——

Senator Bumpers. Well, obviously after 1995 if you go below 1.2 you have got a bankable allowance.

Mr. Rosenberg. Even below 2.5. The 1.2 rate is the rate that is effective in the year 2000, and so that after 1995, if you were, say, at 1.7, you would be able to bank the difference between 1.7 and——

Senator Bumpers. Well, nobody is going to aim for 1.2. If you are going to scrub—if you are at 3 pounds right now, and you are going to scrub, you are going to aim for something under 1.2. You are not going to aim for 2.5.

Mr. Rosenberg. That is correct if you are going to scrub, but there are other things you can do. You can——

Senator Bumpers. That is right, I understand that, but the point I wanted to make, if I were a utility system, and I had—we will say I have 10 units and they were all the same age—this is just a hypothetical case. I might choose to scrub three or four of them and use that allowance to keep the dirty one going for another 20 years. That would be my prerogative, would it not?

Mr. Rosenberg. Yes, sir.

Senator Bumpers. And I would save myself, for example, a tremendous amount of cost by not scrubbing that one. I am going to have to scrub to get these allowances and then I can leave the dirty one going forever.

Mr. Rosenberg. That is correct, and the environment would benefit and the economy would benefit.

Senator Bumpers. Well, I think sometime in the future, I am not suggesting we deal with that in this bill, but sometime in the future we are likely to.

Now, Mr. Badger, my question to you is, and I will make this my last question. This allowance, this trading system, this robust market, in my opinion, is an illusion. I just do not think it is going to work. But let us assume that I have an allowance in the state of Ohio to sell, and you in Maryland would like to buy it.

Now, the business community in Ohio is going to come in and say we do not want you to sell this. We want you to keep this because our power needs in the future are not going to be met or they are going to be very difficult to meet if you sell these allowances.

The consumer-oriented group might come in and say well, we want you to sell them. The ratepayers paid for this; they paid for these scrubbers. These allowances are worth millions and tens and maybe hundreds of millions of dollars. We think that ought to be returned to the ratepayers.

So that is an argument, but to whom do they make that argument? The local Public Service Commission? The local regulatory commission?

Mr. BADGER. Senator, I would think two things are going to happen. First, there is going to be an evidentiary process in the state of Ohio to determine whether the allowances that are generated by the plants located in that state were part of an interstate system, develop a reasonable plan of how these allowances might be used in the future.

I think, as I said earlier, that any commission would certainly first address the extent for which those allowances are needed for other plants within that particular utility or another utility in the state or a part of interstate system before he makes that determination that he is going to agree to have those contracted away.

Senator BUMPERS. Incidentally, Mr. Badger, let me interrupt you at that point. Let us assume you have got plants in three states, and you have built up allowances out of a plant in Ohio, and you are getting ready to sell it to Maryland instead of giving it to a plant in Michigan, that is going to raise a hue and cry, too, is it not?

Mr. BADGER. It is, and I put that in my testimony because not only do you have to worry about your own state and all the utility companies that operate in that state, you should be concerned about the effective operation of regional power pools. I think if you are a member of a pool, as we are of the PGAM system, we have an obligation to ensure that that pool continues to operate.

But to the extent—to the extent that a commission should determine after an evidentiary process that they want those allowances sold and they are going to take a risk on about accommodating future growth, I would expect, just like any other item that the Utility Commission does, it will be subject to a legal challenge, whether that exceeded our authority or whether our action was arbitrary.

Senator BUMPERS. Mr. Rosenberg, on the clean state exemption, on those states that emit less than 160,000 tons and scrub, how was 160,000 tons reached?

Mr. ROSENBERG. This was a committee amendment. This was not proposed by the administration. We do not support that amendment, and so I do not know where they achieved that figure.

Senator BUMPERS [presiding]. I think I know where it came from. [Laughter.]

Senator Ford.

Senator FORD. Mr. Badger, Mr. Tripp remarked a few moments ago about his contractual arrangement. Would that contractual arrangement have to be subject to the approval of the public service commissions if he entered into a contractual arrangement with other utilities.

Mr. **Badger**. Senator, that is some of the discomfort we have. We really do not have an understanding of the expected responsibilities of the states or FERC or the utility industry or co-generators or independent power producers.

One way to look at this is that the utility companies would have the freedom to execute that contract and then have it be subject to an examination in a subsequent proceeding as to the reasonableness of their actions or—and I would prefer this, as I said to Senator Bumpers—I would hope that before a utility company would decide to enter into such contractual relations it would first want to decide the extent to which those allowances may be required to support our system in the State of Maryland, all utilities in that state or members of an interstate system or regional power pool.

Senator **Ford**. Mr. Badger, the public service commission in my state has already voted and put it in writing that emission credits will not leave the state. Whether that will stand up or not, I do not know. As you said a few moments ago, it is all subject to legal challenge.

Somewhere along the way with the complexity of this legislation, we are going to see a lot of legal challenges, and I am not sure what that will do. If the legal challenge is frivolous, if the intent is to slow down the use of scrubbers or whatever it might be, it could be of some jeopardy to the legislation.

I do not know where there is leeway. If the legal challenge is made and it takes two years to get it through the courts, when does the legislation trigger in? Does it still trigger on date of passage and signing by the President or at the interpretation of the legal process? You are geared up to go one way. If a suit is filed and you find out you are going to have to go another way, that jeopardizes not only the commission but the utilities trying to follow the law.

Mr. **Badger**. Senator, as I said earlier in my statement, the discomfort we have, the uncertainties that continue to be placed forward just indicate to me that the conflicts are going to be never ending, and it is almost too appalling to contemplate what is going to happen during this process.

This is the reason that we are going to examine and hopefully have a recommendation to you with respect to other possibilities, including an auction of all allowances that have been advocated by some.

We think you are exactly right.

Senator **Ford**. I might say that the surface mining law was date specific, and it has not yet worked, so it has been along time.

Mr. Rosenberg, on page 10 of your statement in the first paragraph there it says:

> Over time, as existing units retire their allowances will be transferred to new units needing far fewer allowances per unit of installed capacity or, to put it another way, as we build cleaner and cleaner coal-fired units, more and more new units could be constructed. The same 8.9 million tons of annual SO_2 could support three or four times as much installed new fossil fuel-fired capacity. Thus, an emissions cap is not a growth cap.

Do you have a model that you have used on that particular statement that I could use or see that would support that position?

Mr. **Rosenberg**. Certainly we can provide you with detail on that. To state it simply, though, as Under Secretary Stuntz mentioned, the new plants today are achieving with technology roughly .3 or .4 pounds per million Btu. Under the bill, the old plants will be required to come down to 1.2. So for every 100 megawatts at 1.2 that is replaced by a new plant, there will be in this case one-fourth the amount of SO_2 emitted, so that you could in that instance build 400 megawatts at .3 utilizing the allowances of 100 megawatts at 1.2 if you were to retire that 1.2 plant.

That is from where that comes. We will send you for the record, some of the technical data.[1]

Senator FORD. I would like to have that.

Another point that bothers me, we have a lot of utilities on board that are being constructed now nearing completion. The new source performance standards are there. Those new source performance standards will be 0.51 or 0.61 or whatever it might be, but somewhere in that neighborhood.

As I understand it, if this bill is passed and signed by the President and they are not on board prior to that, then they have to go into a reduction, and it is impossible for them to do that, is it not?

Mr. ROSENBERG. Well, that particular plant would not have to go into a reduction. The system of which it is part would have to make up the 4,000 or 5,000 tons of allowances that that very clean plant would emit. So one would not expect that that particular plant which already is presumably at the state of the art——

Senator FORD. But one of those plants to which I am referring now is already on a system that is fully scrubbed. They are at, let us see, 0.67 or 0.7, and the new plants are coming on. It seems to me that if we do nothing to accommodate them, the law then puts them in jeopardy.

Mr. ROSENBERG. I do not know the system, sir. Most of the systems we have seen, particularly in the midwest, have capacity to improve the allowance situation.

Senator FORD. Well, we have one that does not. You might be able to, but a full system of several generating units with 0.7 over all is a pretty good system, is it not?

Mr. ROSENBERG. Yes.

Senator FORD. If you bring something on that is 0.5, what does that then do to the system? There is no way for the system to come down. You see, another worm crawls out of the wall. There are a lot of people out there trying to do what is right, and the consumers are paying for it. There is no consideration given for that company or their ratepayers as it relates to this piece of legislation, no grandfathering.

Mr. ROSENBERG. That is correct, but in many cases scrubbers, for example, which may be operating at 70 or 75 percent capacity or even 80 percent can be operated at 90 percent capacity or 93 percent. So there is room in a whole system quite often to make up that difference.

Senator FORD. Well, that is fine, but when you have a state of the art scrubber on all systems even coming on at about 0.5, you give that system no credit for being good over a long period of time.

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[1] Not received at the time of printing.

Ms. STUNTZ. Senator, if I could just point out, my understanding is that the Committee bill S. 1630 does provide allowances for what we may call "notch babies" starting out between 1985 and the date of enactment of this legislation. Now I do not know that the Administration has taken a formal position yet on that and whether that would address the particular plants about which you are concerned, but I think there ought to be some flexibility in this regard.

Senator FORD. The committee bill, if I am correct, says they must be operating by that time. So if they are completed just beyond that month or 2 or 6 or 8 months or even a year—you know how long it takes to build sludge haul roads. I am sure all of you have been to big generating facilities and seen the sludge haul roads. All we are talking about here today is scrubbers.

Linda, let me ask you this. How many clean coal technologies does the Department have on board that will be completed with a character that would give confidence to a utility to install between now and the year 2000?

Ms. STUNTZ. I will have with me later this afternoon, Jack Siegel who, I am sure you know, is the Deputy Assistant Secretary for Coal Technology. He can give you more details than I on that.

Certainly in the abatement and retrofit technologies, we have quite a number of them.

Senator FORD. Yes, but what will be ready before the year 2000 that could trigger in to give the three-year leeway in order to put the technology on board?

Ms. STUNTZ. There are repowering technologies which under the Administration's bill are subject to the three-year extension. Admittedly, it is going to be a tight fit. Our best estimates are about probably 1998 or 1997.

Senator FORD. Well, you have one, as I understand it, that will be on board with character that will give confidence to a utility by 1998. The others are beyond the year 2000. So with all this work and all this expenditure of money for new clean coal technologies, we are shutting the door with about a three-year window there. With the three-year window you give, if you contract in the year 2000 that is fine; if you have only one, that is all you are going to do.

So you need the confidence level on these other three to five, and that will come, I think, in the period just three years behind the year 2000.

Ms. STUNTZ. We hope to have at least one more of the repowering technologies available before then, but I cannot disagree with you. It is a tight deadline. That is why we are concerned about what the Senate committee did.

Mr. TRIPP. If I could just add to that, Senator. This bill certainly would provide an enormous incentive for firms that are doing research on those kinds of clean coal technologies to get on with the job and to expedite the development of these technologies.

Senator FORD. That is easy for you to say there, but not a dang penny is coming out of your pocket, and you have not been out there laboring 24 hours a day. You have not been spending taxpayers' money to include in research and development. You have not been working on a pilot project or a demonstration project, and those things take time. They are not going to throw away their ratepayers' money in order to get a job done.

Mr. TRIPP. But time and time again, you know, under other bills when there have been goals set for environmental objectives, that has had enormous effects on the development of technology.

Senator FORD. Well, there has been an enormous effect when you put your own cash into it, Mr. Tripp, and when you put your own cash into it that has more incentive than environmental deadlines.

Mr. TRIPP. That is right.

Senator FORD. I am going to quit, Mr. Chairman, and go on. When you work so hard to try to get clean coal technology and spend $60 million of your own state's tax money and do not come to the Federal Government for a handout, and you get close to bringing one on board and you have utilities that are working hard to put it on, and then everybody comes in here and says, well, let us freeze in the dark or get it so dang high that you will not be able to pay——

Mr. Mahoney, just one quick question and I am finished. It is my understanding that the overall national reduction in acid rain has been somewhere between 28 and 30 percent.

Has there been any reflection in your lakes and streams as it relates to that reduction? Can we tell? Is my percentage right?

Dr. MAHONEY. The percentage, Senator, is probably a little bit lower. We would estimate 25 to 27 percent but basically in the same range.

Senator FORD. Well, let us say 28 percent and split the difference. Have you seen any noticeable reduction in lakes and streams as it relates to acid rain?

Dr. MAHONEY. We do not have the historical data record in the lakes and streams to give a good answer for that, Senator. It is only in the last 3 or 4 years that we have sufficient lake survey data to see. We do not see marked changes now, but the watersheds are long integrators, and so it would not be surprising that it would take some years generally to see differences.

The answer is no, though. I am not aware of things that I would cite right away as a major difference.

Senator FORD. Well, there are some things that bother me. Here we are, talking about nothing but scrubbers because we have a deadline that is going to close out new clean coal technologies in which we have one whale of an investment. A couple of companies in this country build scrubbers, and the rest of them are going to take our jobs overseas, as I understand it, if we do not get something done in clean coal technologies that are done here.

I think we ought to try to do it ourselves rather than go overseas like we have been doing on practically everything else. We have talked about nothing but scrubbers, and we have only talked about acid rain here today as if this is the only problem; but we are going to get into toxics.

Acid rain costs will be only about 10 percent of toxics and ozone. Think about that. We are talking here, and we have talked ourselves of wind almost. We have just gotten into 10 percent of the cost under the committee bill which Mr. Tripp supports. It is going to cost roughly $5 billion for acid rain annually, where it is going to cost roughly $50 billion for toxics and ozone.

If we pass Title III of the committee bill, we do not have to worry about the rest of them. We are stuck. We will not even argue about acid rain or anything else. If we pass Title III, we can just quit, and that is the end of it. Then you have won your battle. My coal miners can go home and wait for those brown envelopes to come in on the third or the fifth of the month, and it will look like fall in the lobby of the bank as they open up those checks and you pay for them because they are out of work, absolutely out of work.

I want to clean up the air, but I think there has to be some responsibility to jobs, there has to be some responsibility to industry, and there has to be some responsibility to do it here in America rather than shipping our purchases overseas.

Thank you, Mr. Chairman.

Senator CONRAD [presiding]. Thank you.

The Senator from New Mexico.

Senator DOMENICI. Thank you very much, Mr. Chairman.

Let me ask Mr. Tripp, I notice you are here for the Environmental Defense Fund. Counsel, would it be fair to assume that you also can speak a bit for the clean air coalition on an issue?

Mr. TRIPP. Well, on certain general issues. Dick Ayres is going to be on the next panel.

Senator DOMENICI. I am not sure I am going to be here when Dick comes to testify, so let me pose my question to you or post my concern to you, and perhaps Dick can drop by, if I am not here this afternoon, and fill me in.

I expressed my concern this morning about the apparent unfairness for a state that had scrubbed almost 71 percent of its coal, and was down at .6 in terms of SO_2. And my worry about the future, in terms of where we would get allowances, if we needed some additional capacity.

What I did not say was that, under that scenario, there is not even any assurance that the clean west will remain clean, and clean up where it is currently not so clean. I am referring to three or four plants that clearly are affecting such things as the Grand Canyon and visibility.

I very much would like to try to think of a way to generate the fairness issue for the clean states, and attempt to address in some way, and I know this is tough, the visibility issue that is a growing one, and that I do not think will be the least bit ameliorated under the allowance and trade approach that we have got.

Now that is merely a statement, Mr. Tripp. If you have something to say about it, fine, if not, this afternoon I will try to get by and ask Dick the question.

Mr. TRIPP. Well, I would just make a couple of statements.

Obviously, we are very concerned about the visibility impairment issue, particularly in the West, where there are national parks and very sensitive high elevation ecosystems. And that is one of the reasons that, as far as I know, all of the environmental groups are opposed to trading of credits from east to west, because it could lead to increased SO_2 emissions in the West.

The other thing I would add is I have here a paper that has been prepared by Robert Yunke, an attorney in our Colorado office, and he is here, that analyzes the situation for the 17 Western States, and looks at the opportunities for growth and emission reductions in those 17 States. And New Mexico is one of those states.

And his analysis shows, at least looking at the 17 states, that there are plenty of opportunities for those 17 states to grow and to meet the western cap.

So what I will do is to arrange for Bob Yunke to give you a copy of this. He is here. Maybe he is the best person for you to confer further with about this.

Senator DOMENICI. Let me get that in due course. I can tell you, however, that the language in the bill does not help New Mexico in terms of the so-called clean state allowance.

Mr. TRIPP. That is correct. Again, we are not strong endorsers of the clean state exemption for the reasons that have been stated.

Senator DOMENICI. Let me ask Mr. Rosenberg, the EPA representative here, is it correct to assume that the Administration does not support the bill that is on the floor of the Senate now in its entirety?

Mr. ROSENBERG. Yes, it is.

Senator DOMENICI. Now, might I ask this question? Has the Administration prepared some macroeconomic cost analysis of the President's bill, of the House bill as it cleared subcommittee, and of the Senate bill as it is on the floor thus far?

Mr. ROSENBERG. I believe we are just about finishing that analysis, and I would expect it to be up on the Hill today.

Senator DOMENICI. Well, I think it is obvious, I was on that committee for 12 years, and participating in the last one, and I think I was responsible a little bit for the BACT and for no significant deterioration in pristine areas, and I am very concerned about getting a good bill.

I do believe it is imperative that, sooner or later, we get an analysis of the macroeconomic issues on the President's bill versus the bill on the floor, with a statement from the Administration analyzing what we are getting or are not getting for that difference.

I believe it is imperative that we understand up here what we are—if the bill costs substantially more, precisely what are we getting for it so we can analyze that from the standpoint of macroeconomic costs versus the risks we are taking care of.

We will have that?

Mr. ROSENBERG. Senator, what is coming up today is a cost comparison; it is not the macroeconomic analysis that I understand you are now asking for. I know that there was a meeting yesterday, and there is a real effort to try to put that together as soon as possible.

Senator DOMENICI. So you are going to give us a cost analysis, and in it you will say the President had a bill, he said it was good for the environment, and overall it will cost X amount per year, and X amount by a year out in the future?

Mr. ROSENBERG. That is correct. And we will compare the Administration's original bill with the bill that was passed through the House subcommittee with the Senate bill that is now on the floor.

Senator DOMENICI. Now, let me ask you, with reference to macroeconomic costs, for our people it is not enough to say one bill will cost annually $12 billion, another will cost $36 billion. There has to be some way to understand what that means out there in the marketplace of the United States for jobs, for certain industries that are going to clean up under both approaches, one obviously more than the other, in terms of competitiveness.

And I wonder if you are aware of Data Resources, Inc.'s macroeconomic costs regarding a previous bill, the 1987 approach? Have you seen the Data Resources, Inc. projections there?

Mr. ROSENBERG. I have not. But I would assume that EPA staff has.

Senator DOMENICI. Let me just say to you or ask you when do you think we will get the macroeconomic analysis?

Mr. ROSENBERG. I do not know, Senator. I will have to get back to you this afternoon. I know that people are working on that now.

Senator DOMENICI. All right. Who is going to address the issue that is now becoming front and center, especially with reference to air toxics? Obviously, everyone wants to move ahead in air toxics. There are two issues, one is cost, and one is health.

Who is going to address the issue of what do we get in health risk alleviation?

Mr. ROSENBERG. EPA is preparing that right now, and comparing the cost and the benefit. And we should have that very soon. We have done an analysis of what industries we think would lose jobs under the Senate version of the bill. And that is being finalized. But I know that that is a particular interest of Bill Reilly, and he will be presenting that data within a few days.

Senator DOMENICI. Mr. Rosenberg, if my preliminary information is correct, the air toxic section of the President's bill would have cost $4.7 billion a year once implemented. And the Senate version bill, according to a preliminary Administration estimate, would cost $14.2 billion.

Mr. ROSENBERG. It is actually more than that. The $4.7 billion relates to only the Phase I of the Administration's program; and the $14.2 billion relates to—well, that is the total. Yes, that is correct.

Senator DOMENICI. The point I want to try to get from you is did you, as helpers of the President in putting together the package that used the unreasonable risk language and cost $4.7 billion a year, did you assume you were significantly alleviating health conditions in this country with that bill? And if not, why did you propose it?

Mr. ROSENBERG. We think that 80 percent of the potential risk is dealt with under Phase I of the air toxics proposal, which is the maximum achievable control technology. In both our cases and the case of the Senate bill, we get about the same reductions. And that leaves about 20 percent of the potential risks. And again, these risk analysis are subject to complex calculations, for the residual risk.

We would propose to spend about $1.5 billion on dealing with the residual risk for the 20 percent. And we estimate that it would cost about $6 billion for the Senate version. And that will also lead to significant shutdowns of certain industries because of a bright line requirement that leaves no administrative flexibility.

And remember, the air toxics portion being dealt with by the bill is only 20 to 30 or 40 percent of the total air toxics that the society faces. Half of the air toxics come from automobiles, for example, which has absolutely nothing to do with this calculation.

So it will be our judgment that providing some flexibility, particularly as it relates to the air toxic issue, to older industries, which have limitations on how far a particular, say, a 35-year-old steel plant, can go to meet risk reductions and still be a competitive, viable plant.

I was at a steel plant outside of Detroit the other day,which had 5,000 employees. They had just spent $1 billion to retrofit the plant. It is 50 percent owned by a Japanese company.

They are planning to put a new coke oven in for another $200 million, and yet they do not know whether the calculations, when they are all said and done, will in fact achieve 10 to the minus 4 bright line.

And under the Senate bill, if it did not, notwithstanding that, the only thing the Administrator would have the authority to do would be to close down the plant and send those 5,000 people home, who are earning $25 an hour, two-thirds of whom are minority, rather than give them more time to get to what might be a laudable goal.

Senator DOMENICI. But Mr. Rosenberg, let me make this point. I think what we must find out in some understandable way is if we agree with your last assumption, that there should be some flexibility, what is at risk in some understandable way, everyone wants to do the best possible job in addressing the risk of cancer.

We need to know under a hypothetical like yours, where the bright line would be imposed with no flexibility. What is the effect on society of your bill versus that bill in some way that we can understand?

And I assume somebody is going to work on that in EPA, is that correct?

Mr. ROSENBERG. It is being worked on right now, sir.

Senator DOMENICI. All right.

Let me ask one last question with reference to the trading of the allowances that the Administration supports so strongly as injecting a marketplace concept into this.

Another way to look at it, I hope you know, is that this is a way to—the first effort was to let the clean states help pay for the dirty states. That would not fly around here.

Now what we have got is clean states who might need additional growth are going to transfer wealth to buy the allowances. So we all understand it is an indirect way of getting at that issue.

But I wonder does anybody have any idea what these allowances might sell for at some point in time?

Mr. ROSENBERG. We have projections that assume that by 1995 they will be in the $400 to $500 range, and by the year 2000, they will be around $700 to $800.

Senator DOMENICI. What does that mean, $400 to $500 for what?

Mr. ROSENBERG. Per ton. Each allowance is expressed in a ton of emissions.

Mr. DOWD. Senator, may I respond to that also?

Senator DOMENICI. Of course.

Mr. DOWD. I think the critical marginal cost that we are looking at is that which will exist beyond the year 2000, because that is when the 100 percent offset for the new plants really comes into operation.

Now Administrator Reilly had stated that H.R. 3030, the Administration's bill to get 10 million tons, would cost $3.8 billion. But to get 12 million tons, a 12-million-ton bill would cost $8 billion.

Now the average marginal cost of going from 10 to 12 million tons, using Administrator Reilly's figures, is $2,100. I think that that may give one a good feel for what we are really talking about when we get out beyond the year 2000 and have to reduce our emissions to squeeze out that last increment of emission reduction, to scrub low-sulfur coal or whatever in order to generate those allowances.

Senator DOMENICI. My last question is to the EPA representative here.

Do you know historically how much the President's bill, as he has submitted it, how much was the cost of that to America? And how much is that relative to prior environmental efforts that America has made? Is it small or is it 50 percent, or is it more than we have ever done before? Do you have any assessment of that?

Mr. ROSENBERG. In the air area, we estimate we have $33 billion worth of annual environmental expenditures undercurrent law. The President's proposals add approximately $20 billion to that. And so it is a very large percent increase. It is increasing it roughly another 66 percent.

Senator DOMENICI. Sixty-six percent in the air area over what we have already done?

Mr. ROSENBERG. That is correct.

Dr. MAHONEY. Mr. Chairman, if I could I would like to make a very slight correction to a statement that I made so that the record would not be incorrect, if you could take that.

When Senator Ford asked me a question about whether there had been any observations of changes in water quality because of the change in sulfur oxide emissions in the last several years, my answer was, from a perspective of acidity changes, we have not seen those yet.

My staff reminded me immediately afterward that we do indeed see the change in the reduction of the sulfates in the surface waters widely in the country already, and I wanted to add that to my earlier comments so that I would not be misleading as if there were no effects, or no improvement seen at all.

We see the sulfate change. We would expect the acidity improvement to come after some longer time lag.

Senator CONRAD. What kind of improvements do you see? Are these dramatic improvements, marginal improvements? What can you tell us in terms of the extent of the change that you are seeing?

Dr. MAHONEY. They are in the range of the changes in the emissions that we have seen, percentage changes of the emissions we have seen, especially in the Northeast area, which has been the most measured.

Thank you, Mr. Chairman.

Senator CONRAD. Certainly we are glad to get that correction for the record.

Let me ask Mr. Rosenberg, you have just indicated we currently have a level of effort of $33 billion on air and $20 billion would be representative of what the President's bill would do. Do you have any estimate for what the Committee bill would do?

Mr. ROSENBERG. Yes, sir. It is our estimate that the total cost of Senate bill 1630, as passed by the Committee, was $42 billion annually.

Senator CONRAD. So about double the cost of the President's bill in your estimate, is that correct?

Mr. ROSENBERG. Yes.

Senator CONRAD. Let me ask Mr. Rosenberg, further, in looking at Section 3 on the toxics, and I quote this language that appears.

> The bright line test is exceeded. No consideration of costs, cost effectiveness, economic energy or other factors or technological feasibility shall be included in the determination of the appropriate level of any emissions standard under this subsection.

Now, that is the language of the bill that comes from the Committee. Let me just preface this by saying I do not take a back seat to anybody on environmental concerns. I was on the original staff of Earth Day 20 years ago here in Washington.

But I must say, as I indicated in my opening remarks, there has got to be some balance here. I mean, we have to understand the cost effects of what we do for the benefits we derive.

Let me just ask you, do you find that provision that I just cited as a rational provision?

Mr. ROSENBERG. Well, I think the Administration thinks it is a terrible provision that would lead to plant shutdowns that are unnecessary, that will make our industries less competitive than they need to be, and that will have costs that are so great as to dwarf the environmental benefits attributable to the difference between the Administration's proposal, which is to consider health benefits but also take into account economic implications and technology.

This is an area where the costs—the cost benefit relationship is totally out of line with other parts of the bill. We think it is very important to clean up the smog. It is very important to deal with air toxics. In fact, we propose an aggressive program, 80 or 90 percent of which we have agreement on.

It is just this incremental amount where, after a risk assessment, if we determine that, by a calculation that we do not think is precise as the consequences would be, would result in enormous costs and shutdowns, that is a foolish policy.

We have had that kind of legislation in existence right now. That is why we are changing it. We have found that having a bill that relates to air toxics that does not take into account good judgment is not enforceable. It leads to untold litigation and we have been unable, in the last 17 years, to provide the air toxics protection to the American public with a bill that generates that much litigation.

Senator CONRAD. Let me just ask a follow-up. Is there not the potential that the whole air toxics provisions would drive the earlier sections of the bill as well? In other words, in order to meet these kinds of air toxic provisions, you would require scrubbing that would go to the effects on SO_2 and that there is a direct connection between what you do in the air toxics provisions and what happens over in the SO_2 and acid rain provisions of the bill.

Mr. **Rosenberg**. Well, one of the differences between the President's proposals and the Senate is the impact on the electric utility industry, and I think that we think we are asking Mr. Dowd and others to do an awful lot and it is necessary and cost effective and will protect the health and environment, but the requirement that the electric utilities do function under the air toxics provisions as written by the Senate would add billions of dollars to a utility rate with again very marginal environmental benefit.

You might want to comment on that.

Mr. **Dowd**. I would say that that is one area that Mr. Rosenberg and I are in complete agreement on.

Senator **Conrad**. I am glad we have been able to achieve that this morning.

Mr. **Rosenberg**. It has taken nine months.

Senator **Conrad**. Let me perhaps pursue this with respect to a specific provision over in the provisions on acid deposition, and the provisions on NO_x. Specifically with respect to the NO_x provisions, the President's bill would provide a 2 million ton reduction from the projections of rates in the year 2000, the Senate bill a 2.7 million ton reduction, as I understand it. Are those numbers approximately correct?

Mr. **Rosenberg**. I think that is approximately correct. We think it is a little less than 2.7, but the Department of Energy thinks it is a little more.

Senator **Conrad**. So roughly we are on target here. Do you have an analysis at this point of what the difference in cost would be between achieving the 2 million tons that is in the President's proposal and the 2.7 that is in the Senate bill?

Mr. **Brenner**. Our estimate is that the Senate bill would cost about $400 million per year more, beginning in Phase II, to comply than the Administration bill, and most of that difference, that $400 million per year difference, is due to the additional NO_x requirements.

Senator **Conrad**. Do you know if there was any discussion of the economic analysis of that change in the Environment and Public Works Committee?

Mr. **Rosenberg**. We certainly gave them economic data. They were aware of these costs.

Senator **Conrad**. What is the benefit one would derive from that increase?

Mr. **Rosenberg**. Well, they would argue that the NO_x reductions are very relevant to ozone reductions as well as air toxics. We think that yes, up to 2 million tons, that the cost-benefit relationship is on target, but above 2 million tons the curves start to get very steep and we get into much more expensive reductions.

There are also NO_x reductions imposed by the Administration bill, the House bill and the Senate bill that are very substantial in the mobile source area as it relates to automobiles, so that the combination of what is being proposed in the mobile source area plus the 2 million tons in the Administration's proposal we felt was adequate to protect the public health.

Given the fact that we wanted to have cost-effective reductions in a bill that was mounting up in its cost, we felt that that was the right cutoff.

Senator CONRAD. All right. Let me just make one other observation and ask for your response.

I represent the State of North Dakota. North Dakota, as I indicated earlier, is one of three states in the Nation that meets all ambient air quality standards—one of three.

We think that we have the cleanest air in the country, perhaps, certainly in the mainland—perhaps Hawaii would rival us—and we are a state that has coal-based generation of power and we are a state that spent $350 million in scrubbers to clean that up, annual operating cost of over $20 million.

I must say it galls the people in my state, that are suffering economically more than any other state—we led the Nation in personal income decline last year. We are not talking about slow rates of growth in my state, we are talking about personal income decline. We are talking about out-migration. We are the only state in the Nation that has less population in 1990 than we had in 1930. No other state in the Nation has that true of their demographics.

So it is a little galling to see an overall structure that says to those that have not done anything, you are going to be capped where you are, and to those of us who are out and have a real economic need and have spent mightily in order to have a clean industry, you are capped where you are.

Just as a basic principal, could members of the panel respond to that? I mean, how do we go back and tell our people, yeah, this is a fair way to operate?

Mr. DOWD. Senator, I understand what you are saying and I cannot quarrel with anything that you are saying, but bear in mind that this problem stems from the imposition of the cap.

Now, there are other ways of dealing with this problem. It is my understanding that within the last few days the American Public Power Association, the National Rural Electric Cooperative Association and the investor-owned utilities reached agreement on a legislative proposal, a 2.5 pound rate, yes, in Phase I, going to 1.1—not 1.2, but 1.1—in Phase II.

But more important, for purposes of your question, any future plant, new plant that is ultra-clean, and by that we mean anything that emits at or below .3 pounds, would not have to find offsets for its emissions unless it were projected, in a reasonably accurate way, that national emissions would exceed the 10 million ton requirement by 300,000 tons.

Until that point in time, if in fact that point in time ever occurred, we could build—the independent power producers, the cogenerators, could build—future generation when and where needed as long as they met a .3 pound emission limitation, which, as Mr. Rosenberg indicated I believe earlier, is very low.

Only in the event that it appeared that national emissions would exceed by 300,000 tons the 10 million ton reduction requirement would future units, at that point, have to offset even their .3 pound emissions with offsets from other places.

Now, to us this makes a great deal more sense. We have been talking, I think all morning, about the problems that are created by the cap—the regulatory problems, the contractual problems.

Senator CONRAD. Let me just pursue this, if I can. This proposal would meet the goal?

Mr. DOWD. Our understanding is that it would meet the goal, yes.

Mr. ROSENBERG. I would not think that it would. I think that when we showed before the growth projections we were assuming that all new plants would meet the NSPS requirements that would be in the .3 area, maybe a little higher in some cases, a little lower in some other cases, and that there would be a deterioration in the environmental protection of between a million tons a year and 2 million tons a year between the year 2010 and 2020, if in fact there was not the cap.

Now, that is our estimate assuming a 2- to 3-percent growth in electricity demand over this next period.

Senator CONRAD. So how far short—your rough estimate would tell us this would be a million to 2 million tons short of the cap proposal?

Mr. ROSENBERG. That is why the cap proposal, in our judgment—if in fact there is less growth then the cap will have less of an impact. If there is more growth the cap will protect more, and in any event the cap will assure that the greatest development of new technology goes forward that enables us to use our coal in the most environmentally sensitive way.

So the cap has almost a self-fulfilling prophesy of reducing the environmental requirements by stimulating new technology and improved efficiency. Without the cap, I think you are dealing with an acid rain problem and just about the time you get it dealt with it starts to get—you start to slip backward.

The President specifically proposed in his legislation and in his letter the other day that there be a permanent 10 million ton reduction, and we have not seen any other way that makes the permanency as clear as the cap, and that is why we have the support not only of the Administration but of the environmental groups as well.

Senator CONRAD. Let me ask you this: is it not true that there are others who expect that there will actually be an emissions rate decline after the year 2010 because of retirements?

Mr. ROSENBERG. Well, if that occurs then the cap will not have any impact. The cap is neutral. To the extent that there is a decline, principally because new technologies will replace the old plants that are operating at a higher level, then the problem goes away.

Senator CONRAD. But you still have the problem in the year 2000.

Mr. ROSENBERG. It is a very small problem in the year 2000, and in the clean states like North Dakota the Senate Committee has kind of dealt with probably the year 2000 problem by providing an extra 20 percent of allowances.

Senator CONRAD. Well then we will take that as an endorsement by you of that provision.

Mr. ROSENBERG. We do support that provision, but not what has been defined as the Clean States provision, which in lieu of the 120 percent allocation of allowances to these states provides an exemption for those states.

Senator CONRAD. That does go back to the question if you were to be representing North Dakota or if you as a representative of your agency came to my state and tried to explain the fairness of all this based on the underlying concept, you would have a very hard sell. In fact, I would invite you to come out; but you get off the plane first.

Mr. **Rosenberg**. I think this is a complicated bill to explain in any state, and I can assure you that every Senator in every state has some concern. We have attempted to have a fair national program that is balanced, and I guess we will get into that in the panel this afternoon.

Senator **Conrad**. We will, indeed. We will stand now in recess until 2.00 p.m., and we will follow with panel number two at that time.

So we want to thank the rest of you very much for your participation today. You have been an excellent panel. Thank you very much.

[Whereupon, at 1:20 p.m. the hearing was recessed, to reconvene at 2:10 p.m. this same day.]

AFTERNOON SESSION

The **Chairman**. The hearing will come to order.

This afternoon we will continue on the acid rain provisions. We will have some of the same star performers, including Linda Stuntz and Bill Rosenberg. We also want to welcome new members. I do not see Governor Sinner.

I think Ms. Stuntz has an additional statement, so we will recognize you at this time.

STATEMENT OF LINDA G. STUNTZ, DEPUTY UNDER SECRETARY, POLICY, PLANNING AND ANALYSIS, DEPARTMENT OF ENERGY

Ms. **Stuntz**. Mr. Chairman, as I discussed earlier today, the President's acid rain control program is a carefully balanced combination of incentives for lower emissions, for lower costs and more effective technologies and requirements for specific emissions reductions by certain date. We have a market driven approach to minimizing those control costs and achieving those objectives.

Acid rain and acid rain control and the clean coal technology program were intended to be and can be mutually supportive. The clean coal technology program offers the best long-term option to utilization of our vast coal resources in an environmentally sensitive way. Unfortunately, the EPW Bill, as you call it, departs from the President's proposal in two significant areas of particular interest to this panel.

First, the earlier compliance deadlines in phases 1 and 2 of S. 1630 that I mentioned before significantly reduce our ability to offer utilities lower cost control alternatives.

Although the extension for repowering technologies remains the same, advanced abatement technologies would be adversely affected.

The **Chairman**. Now both bills assumed the 1989 passage date, did they not? So I guess that we will move everybody's date forward a year, or what is the assumption there? Do you know?

Ms. **Stuntz**. This is, Jack Siegel, who is the Deputy Assistant Secretary for Coal Technology and who is intimately familiar with the exact time line which all these technologies are on. Certainly things have happened since the Administration put its bill together last spring and early summer. As time goes on, when there is uncertainty in the ability of the utilities to plan and the lead time between those deadlines gets shorter, we think there may come a time when there needs to be some adjustments.

The CHAIRMAN. By the way, I am just advised that the EPW Bill does not assume that we roll forward those dates. Their dates are real dates. Your dates in the President's bill would be moved forward an additional year; is that right?

Ms. STUNTZ. No. They are real dates as well, but they are one year later for both phases than the EPW's bill.

The CHAIRMAN. But they assumed a 1989 passage, did they not?

Ms. STUNTZ. Well, the President hoped for early action on his legislation.

The CHAIRMAN. So a 1990 passage would not make any difference?

Ms. STUNTZ. No, sir. There would have to be an amendment.

The second problem we have with the EPW bill is the lack of regulatory incentives for advanced technologies. The package of incentives in the Administration's bill is very modest, but it represents a critical set of regulatory and electric rate incentives. Without these incentives, the contribution from clean coal technologies could be substantially reduced.

The first key incentive is what I think most people generally call the WEPCO incentive. We believe that EPA's WEPCO decision has placed a chill on utility interest in hosting and demonstrating new clean coal technologies. Judicial action on review of that decision came down a couple days ago may reduce this chill somewhat. There seems to be a reasonable difference of opinion among lawyers.

A company that takes the capital risk to demonstrate a new lower emitting technology still is subject to more regulatory risk and certainly more uncertainty now than a company that pursues business as usual. We think that is a perverse environmental incentive, and we certainly think it is not the way to get new clean coal technologies demonstrated.

Modest Federal rate incentives are provided in the President's bill in the form of a 5-year demonstration program to be used only after a FERC rulemaking. These include an incentive rate of return commensurate with risk, a quicker recovery of capital costs than provided by traditional ratesetting policies, and relatively more rapid amortization of investments.

Moreover, the Administration's proposal would try to deal with the retrospective prudence problems by providing for a negotiated cap up front on the capital cost of advanced technologies. The EPW Bill contains none of these incentives.

Now let me briefly answer the questions that you additionally posed to us on this panel.

We do oppose the clean states provision in S. 1630 for the reasons we have discussed earlier. First, it would exempt from controls high emitting plants in those states which are clean, and although there are some states that are so clean they have no high emitting units, there are other so-called clean states that do, in fact, have a few high emitting units.

Second, because, as the Chairman is well aware, there are some clean states that are not included in the list of seven.

The inclusion of industrial sources within the coverage of the acid rain provision would be impracticable and, we think, not cost beneficial in terms of including the over 5,000 sources that represent less than 1 percent of all point source SO_2 emissions. The opt-in provisions of both the President's bill and the Senate bill are a reasonable way to deal with the issue of capturing those industrial emissions if, in fact, it is cost effective to do so.

We have examined the coal market impacts of the Administration's bill, and we think that there will not be substantially different impacts from the EPW bill, although the more stringent NO_x provisions in the EPW Bill could produce greater coal market impacts.

We do not think that projected coal use would be dramatically reduced in the year 2000, but there would be undoubtedly a redistribution of production. High sulfur coal production from the Midwest and northern Appalachia would shift to low sulfur production from central and southern Appalachia or from the west. Our projections indicate about a 100 to 200 million ton shift in the year 2000 or about 10 percent of projected 2000 production. I emphasize projected, not current, 2000 production.

We also have looked at the impacts on the natural gas markets using the ICF results done for the EPA. The estimate is that natural gas would gain an additional quad or about one TCF of market by the year 2010 or about a 20 percent increase in utility consumption of natural gas.

We have estimates in our written statement on the impacts of these acid rain provisions on other elements of the energy markets, but let me close at this point and respond to questions on those later on.

[The prepared statement of Ms. Stuntz follows:]

STATEMENT OF

LINDA G. STUNTZ

DEPUTY UNDER SECRETARY

POLICY, PLANNING AND ANALYSIS

U. S. DEPARTMENT OF ENERGY

before the

Committee on Energy and Natural Resources

UNITED STATES SENATE

JANUARY 24, 1990

PANEL 2

STATEMENT OF
LINDA G. STUNTZ
DEPUTY UNDER SECRETARY
POLICY, PLANNING AND ANALYSIS
U. S. DEPARTMENT OF ENERGY
before the
Committee on Energy and Natural Resources
UNITED STATES SENATE
JANUARY 24, 1990

Mr. Chairman and Members of the Committee. I appreciate the opportunity to appear before the Committee in support of the President's clean air initiatives. This statement addresses the implications of the acid deposition provisions of S. 1630 on the Clean Coal Technology Program (CCT). regional impacts, and the inclusion of industrial sources.

The environmental benefits which derive from reductions in emission of SO_2 and NO_x have been enumerated by both the Environmental Protection Agency (EPA) and the National Acid Rain Precipitation Assessment Program (NAPAP). The Department of Energy fully supports the goals and approaches set forth in the President's legislative proposal, S. 1490. Our position was made crystal clear in Deputy Secretary Moore's September 12, 1989, statement to the House Subcommittee on Energy and Power:

> "The President has made the difficult choices. This legislation (H.R. 3030) will measurably and dramatically reduce harmful emissions and effects and open opportunities for technological innovation. Accomplishing these goals will cost billions of dollars a year for many years, but we are convinced that the investment must be made."

It is important that both the public and our nation's decision makers understand that real and pervasive energy policy issues are inextricably tied to the question of how the nation should respond to the acid rain issue. Electricity accounts for roughly one-third of the energy consumed in the U.S. Over one-half of the energy used to produce electricity comes from coal. Hence, raising the cost of coal-generated electricity, as any effective acid rain control program must, has a direct impact upon the macro-economy and national employment.

Acid rain legislation will influence fuel choice and affect the balance in use of coal, gas, oil, and other fuels in the U.S. The impacts are not limited to the utility sector, since increases in the use of fuels by utilities will increase the price of those fuels to other sectors.

The price impact of changes in utilities' fuel choices also can potentially influence the price of energy imports and exports, and thereby influence the nation's trade balance and energy security.

Finally, without appropriate incentives for clean coal technologies and reasonable emission reduction deadlines, acid rain legislation could have the effect of locking U.S. utilities into yesterday's technologies. This not only would put the U.S. far behind the progress being made in other countries toward deployment of cleaner and cheaper technologies, but also could make the emissions cap contained in both S. 1630 and the President's proposal much more difficult to accommodate. The President's legislative proposal reflects a reasonable and necessary balance between our desire to reduce emissions and our need to develop the cleanest, most efficient coal technologies. The limited CCT incentives and the compliance deadlines set forth in S. 1490 are critical elements of that balance and should be preserved.

With this general introduction, I will address the specific issues raised in Chairman Johnston's December 12, 1989, letter of invitation, and the Chairman's follow-up questions related to this panel, dated December 18, 1989.

The Clean Coal Technology Program

The President's acid rain control program is a carefully thought out combination of incentives for lower cost and more effective technologies, regulatory requirements for specific emission reductions by a date certain, and a market driven approach to minimizing control costs to achieve those emission objectives.

In this context, acid rain legislation and the Clean Coal Technology Program (CCT) should enjoy a "hand in glove" relationship. After all, the CCT was an outgrowth of the Joint Report of the Special Envoys on Acid Rain. President Bush's decision to fully fund the CCT program, and Congressional approval of funds requested to date reflect the government's solid commitment to developing advanced coal technologies. The CCT program offers the best long-term answer to utilization of our vast coal resources in an environmentally sensitive way.

The deadlines in the Administration's acid deposition proposals are workable, provided that adequate incentives to accelerate deployment of advanced technologies are included in the legislation. Several advanced abatement technologies can be commercialized in time to help meet the December 31, 2000 deadline and a limited portfolio of repowering technologies can be deployed by the end of 2003.

Unfortunately, S. 1630 departs in two significant areas from the President's carefully structured approach to improving the environment while minimizing the costs of doing so. First, the earlier compliance deadlines for Phases I and II under S. 1630 significantly reduce our ability to offer utilities lower cost control alternatives; we cannot support those provisions.

Second, S. 1630's lack of advanced technology incentives, such as protection of clean coal demonstration projects from new source review, is unacceptable to the Administration. A broad spectrum of incentives was discussed within the past two Administrations, dating back to the President's Task Force on Regulatory Reform, chaired by then Vice President Bush, including the Innovative Control Technology Advisory Panel, and concluding with the Domestic Policy Council working group on the Clean Air Act Amendments. The package set forth in S. 1490 represents a very limited, but crucial, set of regulatory and electric rate incentives. Without these incentives, we would not expect to see as much contribution from clean coal technologies. Moreover, with the emissions cap, it is important that we develop and deploy extremely low-emission coal-based electricity technologies. Clean Coal Technologies are the best alternatives. Allow me to elaborate on why we believe that certain incentives are key to successful deployment of advanced technologies, lower costs, and a workable emissions cap.

- The so-called "WEPCO decision" on applicability of new source review regulations has chilled utility interest in hosting CCT demonstrations. (In the WEPCO decision, EPA stated that certain existing power plant boilers owned by Wisconsin Electric Power Company would become subject to new source review regulations if the company proceeded with planned repairs to the units. The decision has tended to discourage utilities from making major investments in existing generation capacity.) In one case, a utility cited WEPCO as a major factor in its withdrawal of an approved project from the demonstration program. Several other CCT projects are in jeopardy because of the requirements imposed by WEPCO. It does not appear reasonable to the Administration to throw regulatory hurdles in front of projects aimed at demonstrating pollution control technologies. S. 1490 largely mitigated the effect of the WEPCO decision on demonstration projects and repowering projects. S. 1630 deleted those provisions.

- Electric utilities are reluctant to undertake the additional risk of demonstrating and deploying new technologies, despite their environmental benefits. It is appropriate to compensate utilities for the additional risk associated with advanced technologies by providing additional reward. Accordingly, S. 1490 contains a very limited set of rate incentives. The proposed incentive program is limited in scope (covering only four plants in each CCT category) and in application (limited to a five-year period initially). The proposal requires the Federal Energy Regulatory Commission (FERC) to institute a rulemaking before implementing its CCT incentive program, which would apply only to power plants regulated by the Federal government. This rulemaking process provides interested parties with an opportunity to address their concerns before any incentive program is adopted by the FERC. The provisions contained in the legislation regarding state regulatory incentives are advisory only, allowing individual states to determine, on a case-by-case basis, an appropriate incentive program.

The Federal rate incentives include an incentive rate of return, a quicker recovery of capital costs than provided by traditional rate setting policies, and accelerated amortization of investments in CCT. Finally, utilities are concerned about retrospective decisions on the prudence of the cost of a technology. S. 1490 provides for negotiated caps on the capital cost of advanced technologies. These provisions were carefully crafted to balance the goals of promoting commercialization of clean coal technologies while protecting ratepayers from unnecessary rate increases. S. 1630, on the other hand, has no electric rate incentives, either at the state or Federal level.

- In addition to limited protection from the WEPCO decision, S. 1490 provides an additional allowance for repowered facilities. The new capacity created by repowering is provided an allowance which is based upon the applicable new source performance standards (NSPS) at the time the unit is repowered. This was included in the bill to accommodate situations in which the unit being repowered was used at a very low rate prior to the repowering. Because a utility would only invest the resources necessary to repower a unit if it expected to run the repowered unit at a relatively high capacity factor, units which had previously run at very low capacity factors would have very low allowable emissions. For units which had run at low capacity factors, these rates would not be technically feasible even for advanced technologies, unless there was an alternative approach to setting their emissions. Section 508(d)(4) of S. 1490 provides such an alternative; S. 1630 does not. Abuse of this provision in S. 1490 is prevented by precluding utilities from trading any "left over" allowances.

While these CCT incentives are limited, they are essential to our ability to achieve the required emission reduction with minimum cost and to ensure that the American people realize the benefits of the Nation's investment in this promising pollution reduction technology.

Clean States Credits Provisions

The clean states credits provisions in section 406 of S. 1630 affect who pays for reductions. The Administration has proceeded on the basis that the companies that are most responsible for pollution should pay for the cleanup, while recognizing the need to minimize the cost of cleanup for everyone. The Administration believes that the appropriate balance of equity is struck in S. 1490. Under the Administration's bill, states which are "clean" bear less burden, and units under 1.2 lbs SO_2/mmBTU are allowed to increase their fuel consumption without having to reduce emissions.

Inclusion of Industrial Sources

It is clear that with a control approach that includes trading, the broader the range of potential participants, the lower the overall costs to society. However, including all point sources of sulfur dioxide is clearly impractical. Sixty percent of the point sources in the NAPAP inventory constitute, in aggregate, over 5000 plants, yet emit less than 1 percent of the sulfur dioxide from point sources.[1]

Industrial sources will have an incentive to enter the control program if profits can be earned through selling allowances. Utilities seeking allowances will have an incentive to identify and solicit allowances from industrial sources able to achieve emissions reductions more cheaply than the utility could. The "opt in" approach taken in S. 1630 and S. 1490 is a reasonable way to expand the range of trading participants, without committing to a program with excessive administrative overhead.

Coal Market Impacts of S. 1630 (Question 2 by Chairman Johnston)

The Department has not conducted any detailed analysis of S. 1630, but we believe that its coal market impacts would be similar to impacts from S. 1490, which have been evaluated by several groups. In general, these analyses indicate that the total tonnage of coal use would not be dramatically reduced by the legislation, but that there would be a distribution impact. Some high sulfur coal production from the Midwest and Northern Appalachia would be displaced by low sulfur coal production from Central and Southern Appalachia. Typical projections for the year 2000 are about 100-120 million tons of coal production shifting regions, about 10 percent of total national production in 2000. Local impacts are somewhat greater: Northern Appalachia loses about 25 percent of its projected mining activity; the Midwest loses about 45 percent. This analysis is based upon projected coal production in the year 2000, not current coal production. Decreases relative to current coal production would be smaller.

In their analysis of S. 1490 for EPA, ICF, Inc., estimated that natural gas could gain an additional quad of market by 2010, with most of it coming from a reduction in projected oil consumption by utilities. This would equate to a 20 percent increase in utility gas consumption relative to levels projected without acid rain legislation. Nonutility consumers of natural gas would see the price of natural gas increase if utilities increased their consumption by such an amount. ICF estimated that the price increase to other consumers of gas might be 5 cents/million BTU for each 0.5 quad of increased gas use by utilities.[2] This comes to about

$1.6 billion dollars per year in 2010. Work done under the auspices of Stanford University's Energy Modeling Forum implies that, for a one quad increase in gas consumption by utilities, the increased cost per million BTUs of gas for nonutility gas consumers might be about four times as high as ICF estimated, leading to nonutility gas cost increases of about $6.4 billion per year.[3] Other ICF simulations of S. 1490, using alternative assumptions, showed essentially no shifts in oil or gas consumption. ICF concluded that total tonnage of coal production would remain almost the same under any of the scenarios which they evaluated.

DOE has reached a slightly different conclusion from EPA/ICF with respect to reduction in coal production. In a January 1989 study, DOE/ EIA evaluated utility fuel choice decisions under a spectrum of analytical assumptions at the request of Rep. Dingell.[4] One of the sensitivity analyses evaluated the effect of increasing coal costs by 10 percent over baseline conditions. DOE estimates that S. 1490 will increase the cost of producing electricity from coal by approximately 5-8 percent. Therefore, the EIA analysis offers some insight into potential fuel use impacts of S. 1490, and similar legislative proposals, in the year 2000. For a 10 percent increase in coal costs, the study concluded that natural gas use would increase about 10 percent (above the 2000 baseline) and coal use would decrease about 4 percent (roughly 30-40 million tons per year). Utility oil use declined by 4 percent (0.1 quad) and electrical generation by nuclear, and hydro energy was unaffected by the increase in coal use costs.

With respect to your question on coal price projections from ICF, I would offer that ICF's analysis is predicated upon the use of a model subroutine which predicts how prices will change for coal as demand for certain types of coal increases. This aspect of their model is similar to models used at DOE, Argonne National Laboratory, and by others. It is a reasonable approach to the issue, but the results must be taken as an educated estimate because similarly high levels of demand for low sulfur coal have not been experienced in the past.

Coal imports and exports could be affected by acid rain legislation. Most coal traded on international markets is low in sulfur, so any increase in the cost of this coal could decrease U.S. exports. With respect to imports, Colombia and Venezuela shipped 1.4 million tons of coal to the U.S. in 1988, out of total imports of 2.1 million tons. EIA projects that level to rise to 7 million tons per year by 2000, not taking into account the possible effects of acid rain legislation.[5] The cost of the Venezuelan and Colombian coal averaged about $35 per ton in 1989 (free at shipside). EIA data indicate that 1 percent sulfur coal from Appalachia sold in the U.S. for roughly $40 per ton (delivered) in 1988. Regional variation in price is very large. Acid rain models predict low sulfur coal prices would increase about 10 percent as the result of acid rain legislation. Hence, depending upon world market conditions, and transportation costs to specific powerplants, imported coal could become very competitive with domestic low sulfur coal. DOE has not evaluated the degree to which foreign coals are likely to penetrate the U.S. market under an acid rain control scenario.

Electricity Market Impacts (Question 5 (b) and (c) by Chairman Johnston)

The derivation of DOE's estimate of the impact of the cap provision is applied to long term impacts (i.e., in the 2020 to 2030 time frame). They are relatively simple and straightforward. However, it should be pointed out that near term impacts (i.e., 2000 to 2010) would be much less, because marginal costs will be lower in the near term (perhaps one-half as much as assumed for the long term) and because there are relatively few new sources requiring offsets in the near term, due to the availability of conservation and low emission energy sources such as solar technologies and natural gas technologies.

The analysis leading to an estimate of $2 billion per year as the cost of the cap in the year 2030 is as follows:

- Emission allowances were calculated for each coal unit in the U.S.. based upon explicit allowances or implicit allowances assuming a 65 percent capacity factor in 2000 and 2030.

- New capacity was introduced assuming a 3 percent/year growth in coal-based generation demand after 2000.[6] New capacity was assumed to emit 0.3 lbs SO_2/mmBTU, half the current NSPS allowable rate. Old capacity was retired assuming a 60 year life.

- Considering growth and retirements, utility emissions would have grown by 1.3 million TPY by 2030, absent additional reductions on pre-2000 units. Hence, a 1.3 million TPY reduction was needed.

- A marginal cost of reduction of $1500/ton SO_2 was assumed to be reasonable for this range of additional control. $1500/ton x 1.3 million TPY = $2 billion per year.

The cost of power calculation for a specific plant also was calculated for a plant built in 2030 as follows:

- The emission rate to be offset was assumed to be 0.3 lbs SO_2/mmBTU, as above. Assuming a heat rate typical of today's powerplants (10 million BTU/MWh), this results in 3 lbs SO_2/MWh of electricity.

- The marginal cost of controlling existing units in the post-2000 period was assumed to be $1500/ton SO_2, or $0.75/pound SO_2.

- The impact upon the cost of power = 3 lbs SO_2/MWh x $0.75/lbs SO_2 = $2.25/MWh. ($2-3 per MWh was offered in the testimony to represent some of the uncertainty inherent in the estimate.) The baseline cost for electric power from a new plant is about $50/MWh.

As noted above, the marginal cost of control assumed for this estimate was one appropriate for the long term. A near term marginal cost of control might be one-half as much, which would lead to cost offsets for new plants built in 2000-2010 of only one-half as much as estimated for the long term.

With respect to your question on whether emission control costs will change over time, let me state unequivocally that the marginal cost of control will change over time. The greatest change will likely occur between 1995 and 2000. In 1995, low sulfur coal will likely be adequate to meet most compliance requirements. However, the greater reductions required by 2000 cannot be met by coal switching alone. Utilities will be forced to use more efficient, and expensive, control techniques, such as scrubbing. Scrubbing typically costs more per ton of SO_2 removed than switching from high sulfur coal to low sulfur coal.

Three other, less dramatic trends are important to note, especially for the 2000-2010 time frame which was referenced in Chairman Johnston's question. They are: (1) the effect of the cap, which forces offsets for new sources; (2) the constant evolution of technology, which can be accelerated by government R&D and technology demonstration projects, and (3) the turbulent market which will immediately follow enactment of acid rain control legislation, and which will likely lead to temporary runups in the cost of low sulfur coal as well as scrubbers. With these in mind, I will address the specific elements of your question, with additional information added, where appropriate.

o Pushing conventional scrubbers beyond 90 percent is possible with use of additives, such as dibasic acid, and with use of alternative reagents, such as sodium, instead of limestone. Conventional (90 percent removal) scrubber costs estimated by ICF/EPA appear to average about 7.5 mills/KWh (levelized 1988 dollars for a large, high sulfur coal retrofit).

ICF reports that a 95 percent efficiency could be attained with an additional 0.4 to 0.8 mills/KWh.[7] Assuming one starts with a 6 lbs SO_2/mmBTU coal, and a heat rate of 10 million BTU/MWh, increasing the efficiency from 90 percent to 95 percent eliminates 0.3 lbs SO_2/mmBTU at a cost effectiveness of $270 to $540 per ton of SO_2 captured. At 7.5 mills/KWh, the cost effectiveness of the first 90 percent reduction would be about $280/ton SO_2. Hence, the cost effectiveness of controlling from 90 percent removal efficiency to 95 percent may be twice as high, or alternatively, about the same, as the cost effectiveness of achieving 90 percent control with conventional technologies, depending upon which costs estimates you believe are more nearly correct. In either case, it should be noted that the cost of electricity from the plant is not sharply increased by selecting the more efficient approach. Generation costs for a retrofit unit with uncontrolled costs of 30 mills/KWh would increase about 25 percent to achieve 90 percent control and about 28 percent to achieve 95 percent control.

Retrofit scrubbing of a low sulfur coal plant would cost less per KWh, but more per ton reduced, because less SO_2 is reduced per unit of energy. Overall cost effectiveness for a large low sulfur coal-fired plant might be $1100/ton SO_2.

Scrubbing at smaller plants generally costs more per ton than scrubbing at large plants. For example, scrubbing a 200 MW high sulfur coal plant costs more than 50 percent more per ton of SO_2 removed than scrubbing a 500 MW high sulfur coal plant.

Over time, it will be necessary for utilities to apply scrubbers at sites having progressively poorer cost effectiveness (older, smaller, lower sulfur units).

- The cost of switching coals at existing plants is sensitive to the geographic location of the plant and the stringency of the control program. In some eastern areas, low sulfur coal carries a high premium. In some western areas, little or no premium exists. In Federal Region V (the Midwest), we estimate that the premium for a switch from high sulfur coal to low sulfur coal will have a cost effectiveness value of $230/ton SO_2 reduced.

- As noted above, the cost of retrofitting 90 percent-efficient scrubbers at a large high sulfur coal plant is about $280/ton SO_2. This estimate reflects the recent decline in control costs as the technology has matured. Cost estimates in the early 1980s were about 60 percent more than this figure for similar conditions. We believe that the downward trend in costs will continue. If the CCT is successfully completed and appropriate deployment incentives are adopted, then we would expect to see costs decline from current estimates by about 25 percent by 2000 and as much as 50 percent by

2005. These levels of cost effectiveness ($140/ton and $70/ton, respectively, at a large, high sulfur coal plant) would make technology options very competitive with fuel switching at such plants.

- Because the SO_2 emission cap requires utilities to offset emissions from new sources, the emission rate of new sources is important to understanding cost effectiveness trends over time. If the most advanced technologies are used, then SO_2 emissions from new sources in the future could be one-sixth the level of today's new source emission rates. Offsetting this small level of emissions could be managed largely through expected retirements of older powerplants, leading to constant or even declining control costs for the nation. However, if only "very good" technologies are used at new coal plants, with emissions which are still 50 percent below rates from today's new plant technologies, then SO_2 reductions from retirements may not keep pace with SO_2 increases from new units, and the marginal cost of control could increase over time. It should be reiterated that whether control costs increase or decrease in the post-2010 time frame is highly dependent upon whether we are successful in deploying "super clean" coal technologies by then, and upon the demand for coal-generated electricity, which will drive how many new coal plants will be built and require sulfur dioxide offsets.

I appreciate the opportunity to present the Department of Energy's views on certain aspects of the President's Clean Air Act initiatives. I am available for any questions you may have.

ENDNOTES

1 The 1985 NAPAP Emissions Inventory (Version 2), EPA-600/7-89-012a, November 1989, p. 2-11.

2 Economic Analysis of Title V of the Administration's Proposed Clean Air Act Amendments (H.R. 3030/S. 1490), ICF Resources, Inc., September 1989, p. 30.

3 North American Natural Gas Markets, Energy Modeling Forum, Stanford University, February 1989, p. 93.

4 Electricity Generation from Natural Gas: Prospects and Implications for the United States, EIA (SR/EPD/89-01, January 1989).

5 Annual Prospects for World Coal Trade--1989, DOE/EIA-0363(89).

6 Demand growth could be reduced by fuel switching or conservation. However, 3 percent/year growth in coal-based generation is believed to be reasonable. The draft Annual Energy Outlook--1990 reflects 3.5 percent/year growth in coal-based generation between 2000 and 2010.

7 Economic Analysis of Title V of the Administration's Proposed Clean Air Act Amendments, ICF Resources, Inc., September 1989, p. 28.

The CHAIRMAN. Thank you very much, Ms. Stuntz.

Mr. Rosenberg.

STATEMENT OF WILLIAM G. ROSENBERG, ASSISTANT ADMINISTRATOR, AIR AND RADIATION, ENVIRONMENTAL PROTECTION AGENCY

Mr. ROSENBERG. Thank you very much. I would like to begin by discussing some of the regional impacts of the bill. Unfortunately, any acid rain proposal has more regional impacts than we would like, but the issue that comes up is are the regional impacts based on environmental requirements, and are they fair?

These are charts that we did touch on a little bit this morning, so I will not take very much time on it. This is intended to point out that while the nine states that have the greatest impact, the greatest requirements, and which were responsible in 1980 for half of the emissions, they are being called on to reduce 65 percent of the reductions, so that they have two-thirds of the reduction requirements in those nine states but they are only bearing 50 percent of the cost.

So the conclusion of this chart is designed to point to the idea that in terms of overall cost, even though there are greater reductions being required in the dirtiest areas, their percentage of the cost is not out of line with their percentage of the contribution to the problem.

We had some debate on that in the House, and that is whywe happened to have that.

The CHAIRMAN. What is their cost of electricity going to be after cleanup as compared to the other states?

Mr. ROSENBERG. Could we put the next chart up?

On a national basis the bill will cost about $4 billion, which is roughly a 3-percent overall national cost in expenditures for electricity.

The CHAIRMAN. This is the acid rain provision?

Mr. ROSENBERG. We are just talking about acid rain here, yes, sir.

It is interesting that in phase 1, which seems to be the most controversial area, the 107 versus the 20 plants and what happens first, the overall cost is only 10 percent of the total cost of the bill. The reason for that is that we are measuring from 1980, and some of the reduction has already occurred. So on a national basis there is a 3 percent impact.

What this is intended to do is point out on the five hardest hit states what happens vis-a-vis the rest of the country. Starting on the right-hand side, which is the national question, there would be a weighted average of 1987 rates of roughly 6.7 cents per kilowatt hour. That is the yellow level.

The impact of this bill to that on a national basis is roughly one-tenth of one cent per kilowatt hour, which comes out to be about 3 percent impact.

In the states most impacted by the bill, however, they have the smaller amount of the emissions and currently enjoy rates that are roughly 10 percent lower on an average than the national rates. The yellow bar there says 6 cents.

So on a current basis, 1987 basis, the hardest hit states are enjoying a 6 cents per kilowatt hour average rate, whereas the Nation is 10 percent higher. Those states would have on a statewide basis roughly a 5 percent increase in utility rates.

The CHAIRMAN. What is the yellow now?

Mr. ROSENBERG. The yellow is the current utility rate, the 1987 utility rates in those areas.

So in Ohio, West Virginia, Indiana, Missouri, and Kentucky it averages 6 cents a kilowatt hour. In the rest of the Nation, the average rate is 6.7 cents, which says that in these various states they roughly enjoy a 10 percent lower average rate.

The CHAIRMAN. But their cleanup cost is only 3 percent?

Mr. ROSENBERG. Their cleanup cost will be 5 percent or 3 cents a kilowatt hour. So at the end of three-tenths of a cent per kilowatt hour, in the year 2001 they would have an average rate, we estimate, of 6.3 cents, which is 5 percent higher than it would be without the bill.

The CHAIRMAN. But cheaper than the rest of the country?

Mr. ROSENBERG. But still cheaper than the rest of the country after the cleanup because the rest of the country starts at 6.7. Their average rate will go up .1 cent.

The CHAIRMAN. Some utilities or some states vociferously deny that?

Mr. ROSENBERG. Well, it is more the utility system than the state system. There are some people who would argue that the trading system will not work, so the 20 percent savings, we think, as a result of the trading system would raise the price. Even if you raise those marginal amounts, which is the black box, 20 percent, it does not make much difference.

It is kind of interesting because as we were sitting here and all the questions started to come about the states, I asked Mr. Brenner to give me some information. So since some of you are here, I will tell you what I think will happen in your state.

In Louisiana which right now has utility rates that are 90 percent of the national average, we estimate the rates as a result of this bill will go up less than 1 percent, .9 percent. That is assuming you have to buy the permits that have to be bought and whatever.

I do not yet have North Dakota. We will get that.

In Kentucky now, not counting TVA, the Kentucky utility rates now are 70 percent of the national average, and the rate in Kentucky we estimate would go up approximately 3.4 to 4 percent so that there would be a substantial increase.

In New Mexico, Senator Domenici was correct in believing that the rates there are 130 percent of the national average, but we estimate the rates would go up in 2005 less than one-tenth of 1 percent.

The CHAIRMAN. This is all for the President's bill?

Mr. ROSENBERG. But it should not be materially different. The President's bill and the Senate version of the bill in this section of the Clean Air Act are very similar.

Senator CONRAD. Mr. Chairman, if I might just interrupt. I want to make sure that I understand what is being presented.

Are you just talking about the acid rain provision?

Mr. ROSENBERG. Yes, that is all.

Senator CONRAD. If we are worried about the total effect of this bill, the numbers that you are giving here are not representative of the effect of the total bill, but just this section of the bill?

Mr. ROSENBERG. Yes, sir. It is my understanding the second panel was supposed to discuss the impacts of the acid rain portion of the bill.

Senator CONRAD. I just want to make sure that nobody walks out of here thinking that these numbers are the cumulative effects of this legislation.

Mr. ROSENBERG. And, as I think Senator Johnston said, this is only 10 percent of the total potential cost of the Senate bill.

Now it is a significant 10 percent and it will probably get more than 10 percent of the debate. I am certain of that. But the impacts on rates effected in specific utilities potentially could be in the 10 percent range in some cases. But that will be a rare case where the average rate increase of a utility system would go up as much as 10 percent. That will be very rare in your state.

Mr. Brenner tells me that the average increase will be about 2 percent as a result of this bill.

Senator CONRAD. Of just these provisions of the bill?

Mr. ROSENBERG. Of the entire acid rain provisions of the bill. That includes the cap and the trading system and the other things that we have been discussing.

Senator CONRAD. What is the assumption on the price of gas that is inherent in those predictions?

Mr. BRENNER. It assumes an increase in the price of natural gas over time. I would have to look up exactly what the amount is. But we project an increase in the price of natural gas as you go into the out years as we projected oil prices would go up, too.

The CHAIRMAN. A dramatic increase?

Mr. BRENNER. Excuse me just a second. That has very little effect on the overall acid rain control cost. We only see a small amount, about one quad of natural gas being used for compliance purposes for acid rain.

Mr. ROSENBERG. We think that the other regional impact is obviously the impact on high-sulfur coal miners and coal miners generally.

EPA agrees with the Department of Energy that roughly there is a balance between the high-sulfur coal jobs that might be lost, which are around 17,000, and those low-sulfur jobs that might be gained. But they are in different locations within Appalachia.

And you can see here, this is the estimate of total coal employment. With the bill it is estimated to go up. The job slots gained are between 19,000 and 21,000, and the job slots lost are 15,000 to 17,000.

Now that is a macro number, and I think, in fairness to Senator Rockefeller and others, in certain areas there are winners, in certain areas there are losers. And they are generally not in the same exact location. It is a rare situation when they are.

But it does point out the importance of the clean coal technology program and the need to put back into the bill the incentives for clean coal technology that were in the President's proposals, which do not call for any loss of environmental benefits as far as we can tell, and does not call for a subsidy on the part of other states.

But it does make it easier for new technologies to be deployed during the demonstration phase that the Department of Energy is working on and thereafter.

I know that the committee staff has a list of those technical amendments, but they are very important and we would hope that they would be put back into the bill. And they would alleviate in the long run the adverse impact on the coal industry.

I have finished my testimony, Mr. Chairman.

The CHAIRMAN. Next we have the very outstanding Governor of North Dakota, our good friend, Gov. George A. "Bud" Sinner.

Governor, welcome to the committee.

STATEMENT OF HON. GEORGE A. SINNER, GOVERNOR, STATE OF NORTH DAKOTA

Governor SINNER. Senator Conrad and Senator McConnell, thank you for being here.

Chairman and members of the Senate Energy and Natural Resources Committee, I am George Sinner, the Governor of North Dakota. Thank you for the opportunity to testify on S. 1630 to express some North Dakota concerns on this bill.

One of the key points that I want to make here is the damage that has occurred to rural, production-oriented states, and ours particularly.

The rural states which have heavy production economies in the raw products of food and energy have suffered mightily in the 1980s. Populations have been static or declining in rural states, even while urbanization problems of drugs, crime and pollution grow exponentially.

Truly, the urbanization of America has brought many new problems that we probably should look at in terms of urbanization.

Continuous erosion of our production capacity by measures such as you are considering today will result in a further exodus of our people to large metropolitan areas, and will speed the rate of decline in quality of life, both in rural and metropolitan areas.

We will lose highly skilled workers, our children, our social fabric and our way of life, even while Congress struggles to enact rural redevelopment legislation.

I am going to have somebody put some charts up here.

North Dakota is one of three states meeting all the standards of the current Clean Air Act. It is considered one of the most, if not the most, rural states in America.

We have been literally decimated by a combination of factors over which we have had no control. The too strong dollar in the early 1980's cut our exports. We lost our agricultural markets to the tune of something like 25 percent. OPEC oil dumping virtually ended our oil and gas exploration until just recently, and significantly limited production. And the last 2 years of drought have devastated our farm and rural communities.

Just to give you an example of the devastation. We are running the state today with a budget that is virtually the same as the 1981 budget in actual dollars. We have cut the budget harder than any other state in the United States. But there has been no alternative because income has declined so dramatically.

In other words, our state budget is really roughly the same now as it was in 1981. There has been a 42-percent inflation during that period, and we are using the same actual dollars, almost.

Mr. Chairman, you have toured our coal fields in North Dakota, and you have seen first hand the enormous potential our lignite reserves offer. Our state has an estimated 35 billion tons of recoverable reserves, enough to last 1,000 years.

And let me comment parenthetically that I applaud Mr. Rosenberg's insistence that clean coal technology be put back in here. Because, obviously, the Nation cannot turn entirely to gas, it cannot turn entirely to nuclear or alternative fuels, but eventually must face the need to use these abundant resources.

Our greatest concern at this point is that the legislation you are hearing testimony on today will stop development of this resource dead in its tracks. We are not asking for an exemption from S. 1630, we are asking for reasonable emission standards and credit for North Dakota's successful efforts to maintain clean air.

North Dakota is the 11th largest coal producing state in the Nation, and as I said, one of only three states to meet all federal clean air standards, both ambient and stack standards.

We are a clean state because the utilities and cooperatives operating clean coal-fired powerplants in North Dakota have invested $350 million for sulfur-dioxide removal systems. Comparatively, North Dakota has a very high percentage of its coal-fired generation scrubbed. Only three other states have a higher percentage.

That chart shows you the percentage of our coal-fired generation that is scrubbed. And you can see we have done a good job.

Presently, our state's lignite industry nearly creates 18,000 jobs for North Dakota people and generates more than $1 billion in business activity for the state each year. But instead of expanding, we see legislation, in this case, coming out of Washington, that will stop growth in North Dakota in the future.

S. 1630 unfairly discriminates against clean states such as North Dakota.

Powerplants that have done little or nothing to control SO_2 are given growth allowances precisely because they have not cleaned up their plants, and for reducing their emissions below the 1.2 per million Btu pound level, while existing clean plants like ours will get no growth advantage. Nor will they get any advantage for the money they have invested long since.

As you can see in this very, very dramatic display, we have units in North Dakota that are well below the proposed 1.2 pounds per million Btu of SO_2 standard. These units have spent millions of dollars to install scrubbers, and are capped at .4 pounds per million Btu standard under the proposed legislation.

These clean units will receive no growth, nothing as an allowance for their past efforts under this bill. And that money was in most cases invested around 1980.

However, look at the next case. A utility with a dirty plant, it could reduce its emissions from a high level to a low level by making the same investment that was made way back in the early 1980s by the Basin Electric Power Cooperative at its Antelope Valley Plant in North Dakota, for the same investment 10 years later.

However, this utility with the dirty plant would receive an allowance for reducing below the 1.2 level, enabling it to build, guess what, another plant, while Basin Electric remains capped at its present level.

In essence, Mr. Chairman, there is a dirty plant bonus that rewards dirty plants. The concept is grossly unfair to North Dakota with its newer, cleaner plants.

We have not tried to include in those numbers any of the dollar costs, and if you figured the investment value of those early investments over there that were made in the early 1980s, you would see that it exacerbates the problem.

But because we cleaned up early we get penalized with no growth potential.

Now the clean state amendment is vital to North Dakota and all states that have cleaned up their emissions. And this is really a separate issue, but in many ways it almost makes this point more clear and emphasizes how important this is in the rural states.

The clean state amendment would allow, at least, to establish a reasonable level of SO_2 emissions based on a 1996-1998 time frame, rather than the 1985–1987 period, the time when North Dakota's generating capacity was way down.

While this provision allows no expansion, it does enable North Dakota to continue operating our existing plants at current levels.

Let me also point out that the average emissions of all our plants is 1.1 pounds per million BTU, and we are going to get no growth expansion capability for all that work we have done.

Now I realize that there are states that have been able to keep their SO_2 emissions extremely low because they have access to economical supplies of clean fuels. But such states have not made the major investment our state has to clean up their coal-based generation. And we have forced our people and worked with them to get this done.

In North Dakota we have spent $350 million on air pollution controls alone, and another $350 million on other environmental protection efforts. All of this was done at a time when the nation desperately needed energy expansion. The cost is really much higher, since many of our scrubbers have been installed five years ago, as I pointed out.

States that have made the investment deserve credit for their efforts.

On the NO_x issue, we are not opposed to the more stringent NO_x rate standards contained in the bill. North Dakota's cooperatives and utilities are willing to make additional investments in pollution control equipment to reduce nitrogen-oxide emissions.

However, it is unfair to require a utility to make the investment to reduce its emissions to the new rate, and then force it to curtail generation by placing an unreasonable cap on nitrogen-oxide tonnage, which is based on baseline years when North Dakota's generation capacity was down.

It simply is not fair.

Thus, we believe the tonnage cap provision for nitrogen-oxide levels should be eliminated. As the bill is currently drafted, many North Dakota plants would have to operate well below their present capacity. Some as low as at 33 percent.

This would result in power production from Cyclone coal-fire generation in North Dakota falling from more than 15 million megawatt hours in 1988 to less than 11 million megawatt hours after the enactment of all these provisions.

The reduction would come at a time when North Dakota is being asked to increase its coal-fire generation to replace decreasing federal hydro-based generation that has declined due to the drought in the Northern Plain states.

North Dakota also has a number of Cyclone boilers built especially to handle lignite. Because there is no known technology for economically controlling NO_x from Cyclone boilers, it is important that the NOx standard for Cyclones be met as specified in S. 1630.

On clean coal technology, North Dakota believes that clean coal technology should play a key role in helping the nation meet new clean air standards. Therefore, we strongly encourage the inclusion of incentives for all clean coal technology to include pre- and post-combustion processes, not just repowering.

For example, coal beneficiation is a promising clean coal technology that reduces coal moisture and sulfur to create a more efficient and cleaner burning product.

This pre-combustion process is presently being considered for North Dakota lignite, but the bill limits incentives to repowering, excluding technology which could play an important role to further reduce emissions.

An issue that has been very dear to me is the issue of environmental equity. Throughout the acid rain debate, the expression pollution knows no boundaries has been used as a reason to include clean states like North Dakota in a 48-state bill. But the same reasoning can be applied to support the need for environmental equity on an international level.

Our nation's borders are not walls that prevent pollution from Canada and Mexico from affecting our environment. How can we make a mockery of this by saying that our competitors do not have to meet the standards; we will welcome their products, but they can do it any way they want to?

North Dakota is greatly concerned about increasing competition from Canadian electrical generation as a result of this acid rain legislation. If Canada can export electricity to this country in direct competition with our state's coal-fire generation, it should at least have the same or similar environmental performance standards so that everyone competes on a level playing field.

And I might add parenthetically, so if in fact this is a clean air bill, it will in fact clean up our air.

Presently, Canada does not have a single scrubber on any of its 29 coal-fire stations which generate 19,000 megawatts of power.

I think we have a map that shows that. And I have some more handouts of those maps.

You can see that all the scrubbers on the North American continent are in the United States. There are none in Mexico and none in Canada. The same situation exists on the Mexican border.

We understand that Canadian provinces are adding 1,800 megawatts of unscrubbed coal-fire generation in the next 8 years, and we expect that this energy will be exported to the United

States under the Free Trade Agreement. And if that trade is going to be free, it must also be fair.

By allowing Canada to capture markets in the United States through unfair competition, not only do we export jobs and dollars, but we also become even more dependent on foreign, sometimes unreliable energy.

Finally, Mr. Chairman, energy sourcing in this world remains problematic. Oil and gas are finite, and that is putting it mildly.

The United States now imports nearly half of its oil, I think in most recent months more than half of its oil.

Nuclear energy comes with its own set of problems. It is necessary, and we must solve the problems, but it has them.

Renewable and solar energy sources remain at various stages of development and are probably not all that reliable, given the fact that we are now facing very, very low food reserves globally.

In the meantime, we have coal, and we have it in abundance. This is not the time to stop development of our country's vast coal resources. North Dakota has proven its ability to develop its coal resources in an environmentally sound manner. We can continue to do so if we are not denied the opportunity. We can provide reliable low cost electrical power for the Nation and create jobs for future generations and for a rural economy that desperately needs them.

In light of the significant problems this bill causes coal producers, utilities and their consumers, the Senate should consider appropriate alternatives to the acid rain provision of S. 1630. We have attached specific amendments which address most of the concerns that have been expressed in this testimony.

The bill, we think, in many ways is patently unfair and punishes North Dakota precisely because we have been environmentally responsible.

I am grateful for the opportunity to be here and to have a chance to express our concerns to you. Thank you very much.

[The prepared statement of Governor Sinner follows:]

Testimony of Governor George A. Sinner, North Dakota
on Senate Bill 1630 before the
U.S. Senate Energy and Natural Resources Committee
January 24, 1990

Mr. Chairman, members of the Senate Energy and Natural Resources Committee, I am George Sinner, Governor of North Dakota. Thank you for the opportunity to testify on S. 1630 to express some of North Dakota's concerns on this bill.

The rural states which have heavy production economies -- in the raw products of food and energy -- have suffered mightily in the 1980's. Populations have been static or declining in rural states, even while urbanization problems of drugs, crime and pollution grow exponentially.

Continuous erosion of our production capacity by measures such as you are considering today will result in further exodus of our people to large metropolitan areas and will speed the rate of decline in quality of life both in rural and metropolitan areas. We will lose highly skilled workers, our children, our social fabric and our way of life, even while Congress struggles to enact rural redevelopment legislation.

North Dakota, one of three states meeting all the standards of the current Clean Air Act, is considered one of the most, if not the most, rural states in the United States. We have been decimated by a combination of factors over which we have had no control: the too strong dollar of the early eighties cut our exports; the OPEC oil dumping virtually ended our oil and gas exploration and significantly limited production, and the last two years of drought have devastated our farms and rural communities.

One budget for running state government is $1.081 billion for the current biennium. This compares to the 1985-87 level of $1.133

billion and a 1981-83 biennial budget of $1.032 billion. In other words, our state budget is roughly the same now -- not in real terms but in nominal terms -- as our '81 budget. Because inflation since 1981 has totaled 42%, you get some idea of how the current state budget compares to the '81 budget in real terms.

Mr. Chairman, you have toured the coal fields of North Dakota and have seen firsthand the enormous potential our lignite reserves offer. Our state has an estimated 35 billion tons of recoverable reserves, enough to last a thousand years. But our greatest concern at this point is that the legislation you're hearing testimony on today will stop development of this resource dead in its tracks.

We are not asking for an exemption from S. 1630. We are asking for reasonable emission standards and credit for North Dakota's successful efforts to maintain clean air.

North Dakota is the 11th largest coal-producing state in the nation and, as I said, one of only three states to meet all federal clean air standards (both ambient and stack standards) (EXHIBIT 1). We are a clean state because the utilities and cooperatives operating coal-fired power plants in North Dakota have invested $350 million for sulfur dioxide removal systems. Compared to western states and states east of the Mississippi, North Dakota has a very high percentage of its coal-fired generating capacity scrubbed (EXHIBIT 2). Only three other states have a higher percentage.

Presently, our state's lignite industry provides nearly 18,000 jobs for North Dakotans and generates more than $1 billion in business activity for the state each year. But instead of expanding, we see legislation coming out of Washington that will stop future growth of North Dakota's lignite industry.

Growth Cap

S. 1630 unfairly discriminates against clean states such as North Dakota. Power plants that have done little or nothing to control SO_2 are given growth allowances for reducing their emissions below the 1.2 per million BTU/lb. level, while existing clean plants already below 1.2 are permanently capped.

For example (See display), under this legislation, we have units in North Dakota that are well below the proposed 1.2 lbs/mmBtu SO_2 standard. These units have spent millions of dollars to install scrubbers and are capped at a .4 lbs/mmBtu SO_2 standard under the proposed legislation. These clean units will receive no growth allowances for their past efforts under this bill.

However, a utility with a dirty plant could reduce its emissions from a high level to a low level by making the same investment as was made way back in the early 80's by Basin Electric Power Cooperative at its Antelope Valley Station in North Dakota. However, the utility with the dirty plant would receive an allowance for reducing below 1.2, enabling it to build an additional plant while Basin Electric remains capped at its present level. In essence, there is a dirty plant bonus that rewards dirty plants. The concept is grossly unfair to North Dakota with its newer, cleaner plants.

Clean State Amendment

The clean state amendment to S. 1630 is vital to North Dakota and all states that have cleaned up their emissions. It would allow us at least to establish a reasonable level of SO_2 emissions based on a 1996-98 time frame rather than the 1985-87 period, a time when North Dakota's generating capacity was down. While this provision allows no expansion, it does enable North Dakota to continue operating our existing plants at current levels.

I realize there are states that have been able to keep their SO_2 emissions extremely low because they have access to economical supplies of clean fuels. But such states have not made the major investment our state has made to clean up their coal-based generation. In North Dakota, we have spent $350 million on air pollution controls alone, and another $350 million for other environmental protection efforts. All of this was done at a time when the nation desperately needed energy expansion. The cost is really much higher since many of our scrubbers were installed five to ten years ago. States that have made the investment deserve credit for their efforts.

NOx Cap

We are not opposed to the more stringent NOx rate standards contained in the bill. North Dakota's cooperatives and utilities are willing to make additional investments in pollution control equipment to reduce NOx emissions. However, it is unfair to require a utility to make the investment to reduce NOx to the new rate and then force it to curtail generation by placing an unreasonable cap on NOx tonnage, which is based on baseline years when North Dakota's generation capacity was down.

Thus, we believe the tonnage cap provision for nitrogen oxide levels should be eliminated. As the bill is currently drafted, many North Dakota plants would have to operate well below their present capacity, some at as low as 33 percent. This would result in power production from non-cyclone coal-fired generation in North Dakota falling from more than 15 million megawatt hours in 1988 to less than 11 million megawatt hours (EXHIBIT 3). The reduction would come at a time when North Dakota is being asked to increase its coal-fired generation to replace decreasing federal hydro-based generation that has declined due to the drought in the Northern Plains states.

North Dakota also has a number of cyclone boilers built especially to handle lignite. Because there is no known technology for economically controlling NOx from cyclone boilers, it is important that the NOx standard for cyclones be set as specified in S. 1630.

Clean Coal Technology

North Dakota believes clean coal technology should play a key role in helping the nation meet new clean air standards. Therefore, we strongly encourage the inclusion of incentives for all clean coal technologies to include pre- and post-combustion processes, not just repowering.

[illegible] example, coal beneficiation is a promising clean coal technology that reduces coal moisture and sulfur to create a more efficient, cleaner-burning product. This pre-combustion process is presently being considered for North Dakota lignite, but the bill limits incentives to re-powering, excluding technology which could play an important role in further reducing emissions.

Environmental Equity

Throughout the acid rain debate, the expression "pollution knows no boundaries" has been used as a reason to include clean states like North Dakota in a 48-state bill. The same reasoning can be applied to support the need for environmental equity on an international level. Our nation's borders aren't walls that prevent pollution from Canada and Mexico from affecting our environment.

North Dakota is greatly concerned about increasing competition from Canadian electrical generation as a result of this acid rain legislation. If Canada can export electricity to this country in direct competition with our state's coal-fired generation, it should have the same or similar environmental performance standards so that everyone competes on a level playing field.

Presently, Canada does not have a single scrubber on any of its 29 coal-fired stations which generate 19,000 megawatts of power (See attached map). We understand that Canadian provinces are adding 1800 megawatts of unscrubbed, coal-fired generation in the next eight years, and we expect that this energy will be exported to the U.S. Free trade needs to be fair trade! By allowing Canada to capture markets in the United States through unfair competition, not only do we export jobs and dollars, but we also become even more dependent on foreign, sometimes unreliable, energy.

Conclusion

Energy sourcing in this world remains problematic. Oil and gas are finite, to say the least, and the U.S. now imports nearly half of its oil. Nuclear energy comes with its own set of problems. Renewable and solar energy sources remain in various stages of development and are not yet reliable. In the meantime, we have coal and have it in abundance. This is not the time to stop development of our country's vast coal reserves.

North Dakota has proven its ability to develop its coal resources in an environmentally sound manner. We can continue to do so if we're not denied the opportunity. We can provide reliable, low-cost electric power for the nation and create jobs for future generations.

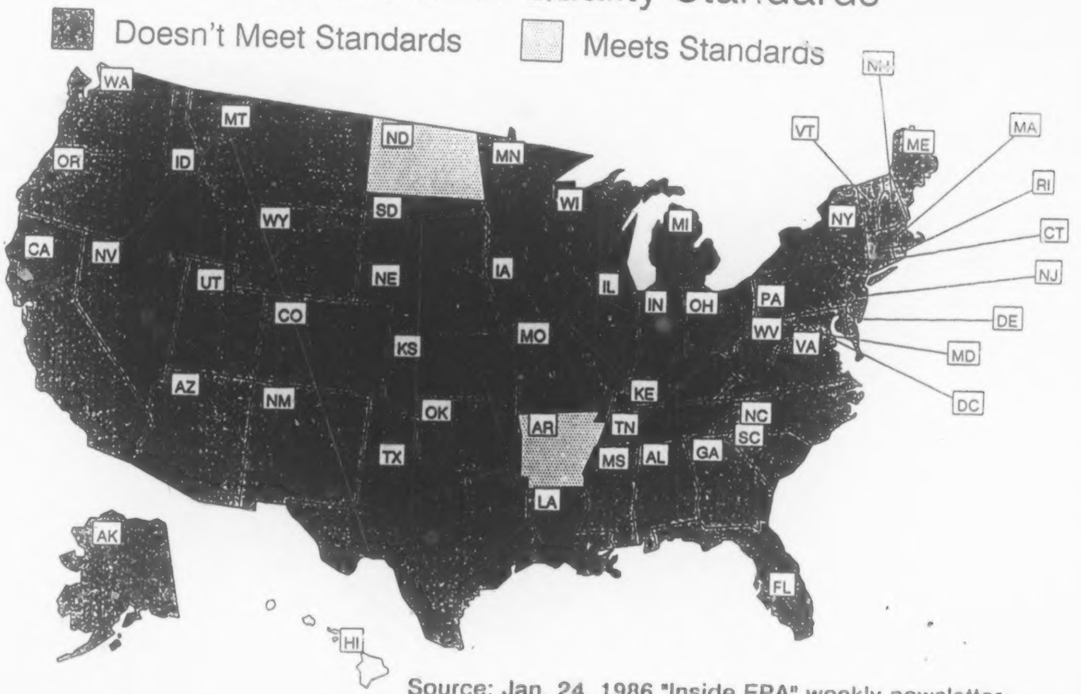
In light of the significant problems this bill causes coal producers, utilities and their consumers, the Senate should consider appropriate alternatives to the acid rain provisions of S. 1630. We have attached specific amendments which address most of our concerns (EXHIBIT 4).

The bill is patently unfair and punishes North Dakota precisely because we have been environmentally responsible. Thank you again for the opportunity to comment on this bill. This is an urgent issue for us.

EXHIBIT 1

States Meeting Clean Air Act Standards

Ambient Air Quality Standards


▨ Doesn't Meet Standards
░ Meets Standards
WA
MT
ND
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OR
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SD
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NY
MA
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CT
NJ
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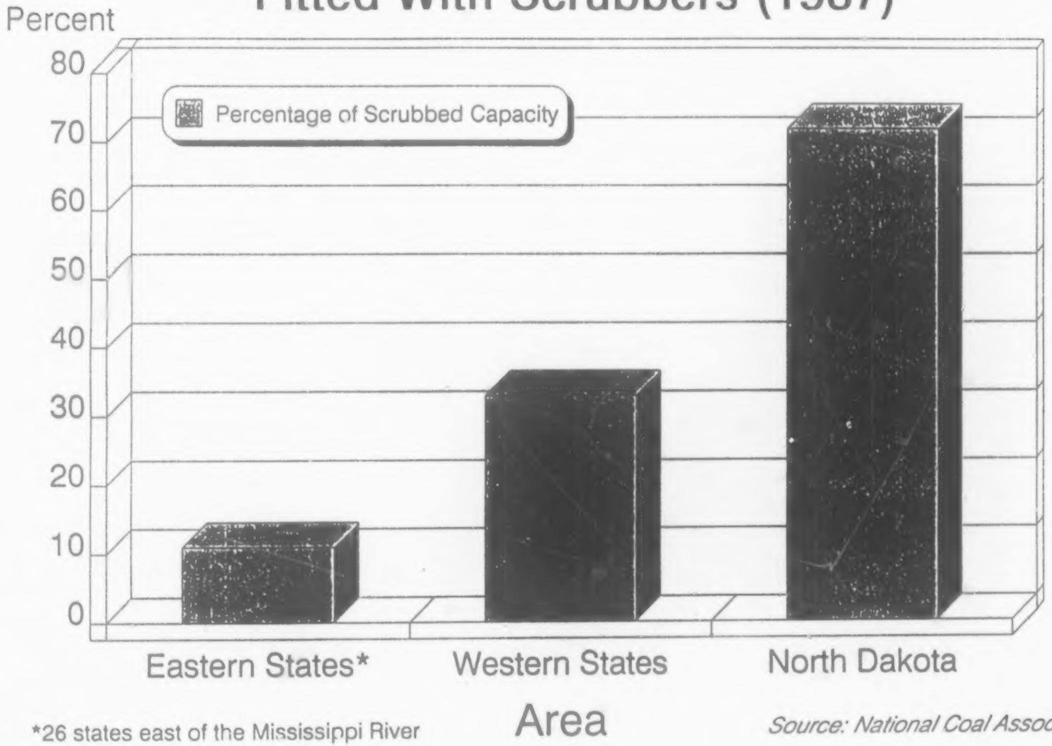
MD
DC

Source: Jan. 24, 1986 "Inside EPA" weekly newsletter

EXHIBIT 2

Coal-Fired Generating Capacity Fitted With Scrubbers (1987)



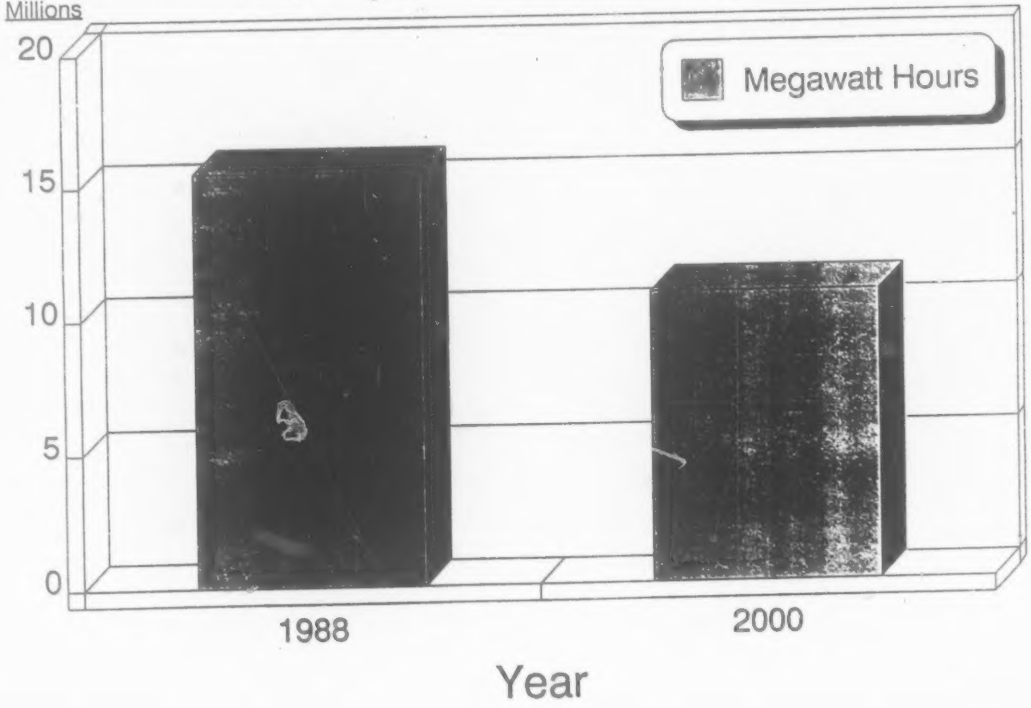
*26 states east of the Mississippi River

Source: National Coal Association

EXHIBIT 3

Effect of NOx Cap On N.D. Generation

Non-Cyclone Generating Units



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PROVIDES ALLOWANCE FOR THOSE UNITS ALREADY BELOW 1.2 LBS/MMBTUS

CREDITS FOR CLEAN STATES

"SEC.406. (a) CREDITS. --Existing units in States in which less than one hundred fifty thousand tons of sulfur dioxide were emitted by utility steam-electric generating units in 1985 and in which more than 50 per centum of coal-fired utility-generated electricity was produced in calendar year 1988 from boilers with a technological system of continuous emissions control shall not be considered affected units for purposes of sections 404 and 405.

"(b) AFTER 2000. --After January 1, 2000, it shall be unlawful for each existing unit in States described in subsection (a) to emit sulfur dioxide during calendar years 1996, 1997 and 1998. The owner or operator of any unit in violation of this subsection shall be liable for fulfilling the obligations specified in section 411 of this title.

"(c) After January 1, 2000, such states described in subsection (a) may have additional emission allowances of sulfur dioxide from the total of all units with an actual 1985 emission rate of less than 1.20 lbs/mmBtu and all new coal-fired utility-generating units at no greater than the product of 1.2 lbs/mm Btu multiplied by the annual average quantity of mmBtu's consumed in fuel by such units during 1996, 1997 and 1998 divided by 2000.

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REMOVES TONNAGE CAP FROM NOX PROVISION

"NITROGEN OXIDES EMISSION REDUCTION PROGRAM

"SEC. 407. (a) APPLICABILITY. --Emission limitations for nitrogen oxides shall apply to coal-fired affected utility units as defined under sections 404, 405, and 406. Such units are affected units for the purposes of this section.

"(b) EMISSION LIMITATIONS. --After January 1, 2000, it shall be unlawful for any affected source that includes one or more affected units to emit nitrogen oxides in excess of the emissions ~~tonnage~~ rate limitation provided by this section: ~~unless the owner or operator of such source has obtained allowances equal to the emissions in excess of those permitted under this subsection. Such limitation is the annual nitrogen oxides limitation that is the product of each unit's baseline multiplied by the following emission rate divided by 2,000--~~

"(1) for tangentially-fired boilers, 0.45 lbs/mmBtu; or

"(2) for dry bottom wall-fired boilers, 0.50 lbs/mmBtu.

"(3) for all other boiler-types, including, but not limited to cyclone, wet bottom, and stoker boilers, their actual annual average nitrogen oxides emission rate as recorded for those units in 1995 and 1996 based on Continuous Emission Monitoring System data required under section 412, or such lower rate as may be specified for such units by the Administrator if the Administrator determines that nonrepresentative operating conditions have resulted in elevated actual rates for such boiler types.

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"(c) REVISED PERFORMANCE STANDARD.--(1) Not later than January 1, 1993, the Administrator shall propose revised standards of performance pursuant to section 111 for emissions of nitrogen oxides from fossil fuel fired steam generating units, including both electric utility and nonutility units. Not later than January 1, 1994, the Administrator shall promulgate such revised standards of performance. Such revised standards of performance shall reflect improvements in methods for the reduction of emissions of oxides of nitrogen.

"(2) Not later than January 1, 1993, the Administra propose standards of performance pursuant to section 111 emissions of oxides of nitrogen from large stationary dies turbine engines. Not later than January 1, 1994, the Adm trator shall promulgate such standards of performance.

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INCLUDES RE-COMBUSTION AND POST COMBUSTION AS CLEAN COAL TECHNOLOGY INCENTIVE

Amend:

Section 402. Definitions

New Subsection "(Q) The term "Clean Coal Technology" means any technology, including technologies applied at the precombustion, combustion or postcombustion stage, at a new or existing unit, which is designed to achieve reductions in emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of anthracite, bituminous sub-bituminous, or lignite coal in the generation of electricity.

New Subsection "(R) The term "Existing Coal Supplier" means any fuel provider or group of fuel providers which supplies an existing unit as of the date of enactment of this Act.

Amend:

Revise title Section 409. ~~Repowered Sources~~ Clean Coal Technology Incentives

New Subsection "(a) Incentives for Existing Units Utilizing Clean Coal Technologies to Maintain Existing Coal Suppliers.--The Administrator shall, in conjunction with the Secretary of Energy, provide incentives to the owner or operator of an existing unit utilizing clean coal technologies which maintain their existing coal supplier as of the date of enactment of this Act.

New Subsection "(1) Compliance dates -- For purposes of complying with Phase I and II emission limitation requirements, existing units qualifying under subsection (a) shall receive an extension of time equal to that period between the enactment of this Act and such date the installed clean coal technology may reasonably be placed in commercial operation.

New Subsection "(2) Emission Fee Reinvestment -- Any fee, tax or assessment required pursuant to this Act will be deemed collected from the existing units qualifying under subsection (a) if said fee, tax or assessment is wholly reinvested in the existing unit's clean coal technology project.

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(a) Monies identified in paragraph (2) may be invested in capital investments; or expensed in the operation and maintenance of the existing unit's clean coal technology project.

(b) Monies identified in paragraph (2) may be used as payments of principle and interest on investments incurred to acquire clean coal technologies.

(c) All investments and expenses of a public utility incurred in connection with a clean coal technology project qualifying under subsection (a) shall be recognized and included by any state or federal regulatory commission in the determination of just and reasonable rates as if the investments and expenses were directly made or incurred by the public utility in the furnishing of electric utility service.

New Subsection "(3) Exemption -- Existing units qualifying under subsection (a) are exempt from Section 111 of this Act.

(a) Said exemption only applies to unit modifications made necessary by the installation of the clean coal technology; and

(b) Said exemption expires upon removal of the clean coal technology.

Optional Subsection "(2) Investment tax credit -- Existing units qualifying under subsection (a) shall receive an investment tax credit of twenty-five percent of the value of the existing unit's capital investment in clean coal technology.

New Subsection "(b) Clean Coal Technology Demonstration Projects.--The Administrator shall, in connection with the Secretary of Energy, select at least one existing unit in each of the Environmental Protection Agency's ten regions which has no SO_2 emission limitations equipment, to be a Clean Coal Technology Demonstration Project.

New Subsection "(1) Maintain Existing Coal Suppliers.-- Those maintaining existing coal suppliers.

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New Subsection

"(2) New Technology Emphasis.--Existing units qualifying under subsection (b) shall be those utilizing new and/or emerging clean coal technologies.

New Subsection

"(3) Emission Limitation Exemption - Existing units qualifying under subsection (b) shall be exempt from Phase I and Phase II SO_2 emissions limitation requirements.

(a) Said exemption shall apply throughout the life of the clean coal technology project;

(b) Said exemption will be revoked at such time the clean coal technology is removed;

New Subsection

"(4) Exemption.--Existing units qualifying under subsection (b) are exempt from Section 111 of this Act.

(a) Said exemption shall apply throughout the life of the clean coal technology project;

(b) Said exemption will be revoked at such time the clean coal technology is removed;

Original subsection "(b) now becomes subsection "(c) etc.

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ENVIRONMENTAL EQUITY AMENDMENT

On page 486, add new section 415:

Sec. 415 Certification of Equivalent Programs

(a) As used in this section, the term --

(1) "Administrator" means the Administrator of the Environmental Protection Agency;

(2) "fossil fuel" means any naturally occurring organic fuel, including coal, crude oil, and natural gas;

(3) "import" means to land on, bring into, or introduce into, any place subject to the jurisdiction of the United States, whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs or trade laws of the United States;

(4) "person" means an individual, corporation (including a government corporation), partnership, firm, joint stock company, trust, association, or any other entity, or any officer, employee, agent, department, or instrumentality of the Federal Government, of any State or political subdivision thereof (including any interstate body), or of any foreign government (including any international instrumentality);

(5) "Secretary" means The Secretary of State;

(b) Imports. -- After January 1, 2000 it shall be unlawful for any person to import electricity or fossil fuel used for electricity generation, unless the Administrator in consultation

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with the Secretary has published a decision, after notice and opportunity for public comment, certifying that the nation from which such electricity or fossil fuel is imported has established and is fully implementing programs that require emissions reductions and controls on electric generating units and fossil fuel processing and transportation facilities on a schedule and in a manner that is at least as stringent as the compliance schedules for and limitations of emissions, including hazardous air pollutants, on domestic electric generating units and fossil fuel processing and transportation facilities.

(c) Certification of National Program. -- The Administrator shall not certify any national program under subsection (b) unless it is determined that--

(1) the nation has adopted legislation or regulations which give the emissions reductions and control schedules for each pollutant the force of law; and

(2) the legislation or regulations include performance standards, reporting requirements and enforcement provisions no less stringent than those specified in the Clean Air Act and the amendments made by subsequent enactments, and that the information contained in such reports is available to the Administrator and the Secretary upon request.

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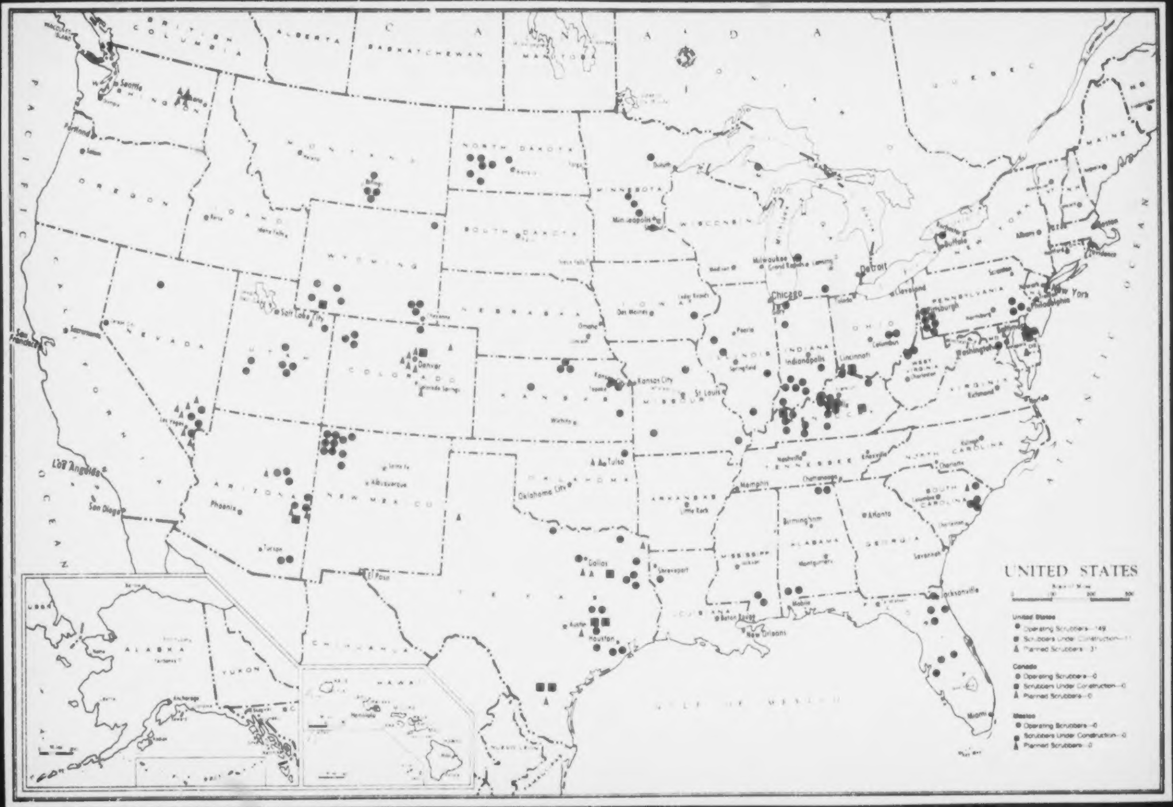
(d) Certification for Participation in the Allowance System. -- If the Administrator, in consultation with the Secretary, determines that the certified program is consistent with the allowance allocation and transfer program and the permit and compliance program set forth under this title, the owner or operator of a steam-electric generating unit under the certified program may participate in the allowance allocation and transfer system under terms and conditions which the Administrator, in consultation with the Secretary, shall prescribe by regulation.

(e) Revocation. -- At least annually, the Administrator, in consultation with the Secretary, shall review each certification made under this section and shall revoke certification, after notice and opportunity for public comment, unless it is determined that the conditions of this section remain satisfied and that the applicable emissions reduction and control schedule for each pollutant is in fact being carried out in such nation. Revocation shall take effect one hundred eighty days after notice of the revocation has been published.

LOCATION OF POWER PLANT SCRUBBERS IN NORTH AMERICA
January 1989


UNITED STATES
United States
● Operating Scrubbers—149
■ Scrubbers Under Construction—11
▲ Planned Scrubbers—31
Canada
● Operating Scrubbers—0
■ Scrubbers Under Construction—0
▲ Planned Scrubbers—0
Mexico
● Operating Scrubbers—0
■ Scrubbers Under Construction—0
▲ Planned Scrubbers—0
CANADA
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
ALASKA
HAWAII

The **Chairman**. Thank you very much, Governor Sinner.

Next we will hear from Ben Yamagata, who is the Executive Director of the Clean Coal Technology Coalition in Washington.

Welcome, Ben.

STATEMENT OF BEN YAMAGATA, EXECUTIVE DIRECTOR, CLEAN COAL TECHNOLOGY COALITION

Mr. **Yamagata**. Thank you, Senator.

In sitting here I cannot help but recollect when I was a staff member and served for this committee many years ago, and I am going to talk about clean coal technologies which you may recall were authorized when I was a staff member here under your tenure. I have been asked, Mr. Chairman, to comment upon the impacts, if any, which the enactment of S. 1630 is likely to have on the development of clean coal technologies, and I appreciate the opportunity to do so.

If coal, our Nation's most abundant fossil fuel resource, is to power our economy in the future, clean coal technologies must bridge the gap between growing demands for energy and heightened attention to environmental protection.

Through clean coal we have an opportunity to address energy and environmental goals as compatible technologies, not as ones constantly pitted against each other.

In support of a sound national energy policy, clean coal technologies will permit continued reliance on our vast domestic coal resources while minimizing environmental impacts.

With respect to economic policy, these technologies will assist in preserving American mining jobs and retaining U.S. industrial competitiveness by generating electricity that is less costly when compared to conventional technology.

Toward improvements in our balance of trade, there is an estimated market potential for clean coal technologies in excess of $50 billion annually by the year 2000.

The **Chairman**. Exports, you say?

Mr. **Yamagata**. Exports, yes, sir.

In furtherance of more stringent environmental standards, these technologies can effectively control or prevent pollution. Some can increase efficiency of coal which in turn will decrease carbon dioxide emissions. Others are capable of simultaneous control of both sulfur dioxide and oxides of nitrogen.

Finally, advanced clean coal scrubbers do not produce the wet sludge which is the waste by product created by conventional scrubbers.

Four weeks ago on December 21, the Secretary of Energy announced the selection of 13 additional clean coal projects costing more than $1.3 billion and bringing the total number of selected projects to 40.

As you know, the Congress last year granted the President's request to appropriate an additional $1.2 billion to the clean coal program. These appropriations will permit two additional clean coal solicitations to be conducted later this year and in 1991.

It is anticipated that with industry's cost-sharing contribution total expenditures of more than $6 billion will have been made toward the accelerated development of emerging clean coal technologies. The impact of S. 1630 upon clean coal should be measured, therefore, against the demonstrated commitment of industry and the DOE to the clean coal program and also weighed against the energy, economic and environmental benefits likely to be achieved if these technologies are given the opportunity to be fully developed.

Where significant admission reductions are required in the near term as prescribed in S. 1630 and given the lack of adequate incentives in that bill to preserve industry's commitment to clean coal, it is unrealistic, I think, to expect major investments in the continued demonstration and early use of these technologies even with the current DOE clean coal program.

Senator McConnell. May I interrupt you for a minute? Is it your view that S. 1630 is an effective mandated scrubber bill?

Mr. Yamagata. I do not think it is, no, sir.

Understandably, I think industry will prefer to use limited financial resources to comply with mandatory reductions by employing known tried and true approaches. Older units will be retired perhaps prematurely. Fuel sources will be switched or plants will be retrofitted with expensive but proven conventional scrubbers.

Clean coal technologies will not be a viable option. This is so because it will take time, perhaps 5 to 10 years beyond the date when a technology becomes commercially available for commercial order. With that maturation period, it is our belief that the latter part of the 1990's and perhaps the first decade of the new century will be required before industry will fully accept and use new clean coal technologies.

The financial commitments required to achieve legislated reductions within the next 4 years and still greater reductions required by the beginning of the year 2000 as called for in S. 1630 are simply incompatible with this clean coal technology development time frame.

The Chairman. Does the President's 1-year difference with EPW help you that much?

Mr. Yamagata. I do not believe it does, Senator. I am going to address that in a moment.

The problem is that we believe we need more time in Phase I if you are going to use clean coal technologies and in Phase II as well.

In an attempt to offset the chilling effect on clean coal resulting from the pending acid rain control legislation, The Clean Coal Technology Coalition has advocated the need for more time so that these technologies might be developed, and also we are proposing additional incentives and modifications to S. 1630 to offset the risk of developing technologies while attempting to comply with the emission reduction requirements.

The President's proposal, which includes several clean coal incentives, recognizes this need for additional incentives as well.

Mr. Chairman, some recognition of this clean coal technology development schedule that I spoke of earlier is given in the Environment Committee's bill in the form of a four-year delay of the emissions deadline to December 31, 2003 if a utility decides to utilize a clean coal repowering technology to comply with the Phase II reductions. Few other incentives are granted, however, in the bill.

Indeed, the Environment Committee's bill does not even include all those provisions in favor of clean coal technologies that have been proposed by President Bush. We have described in our written testimony those provisions of the President's proposal which were not included in the committee's reported bill and would urge this committee to seek amendments designed to reinsert those provisions during Senate consideration of the pending legislation.

Beyond reinstating the clean coal provisions recommended by President Bush, the coalition has also outlined in our written statement a set of modifications to S. 1630 which we believe are necessary to assure this continued and accelerated development. We seek the support of this committee in offering these amendments to S. 1630 as well.

Enactment of an acid rain abatement program without adequate clean coal provisions for additional time, expanded incentives to use new technology, and flexibility and use of those technologies to meet control requirements will seriously jeopardize the ongoing program. The amendments we have outlined in our testimony are designed to acquire the needed time, incentives and flexibility.

During his press conference two days ago, I listened to Senate Majority Leader Mitchell reflect upon the need to provide leadership to the world's peoples in securing a cleaner environment. He noted in his comments that within the next 40 years the population of planet earth will double and that about 90 percent of that growth will occur in less developed countries.

I would respectfully note that many of those less developed countries have huge indigenous resources of coal and that coal will be used. It will be used undoubtedly to power those nations into the 22d century. U.S. clean coal technological leadership and know-how positions U.S. industry to take advantage of a huge export market with its attendant favorable impacts upon our own balance of trade. We can also be the world's leader in providing those developing countries with technologies that will permit the use of their coal in an environmentally acceptable way.

Consequently, it is reasonable to assert, I think, that a sensible energy and environmental policy here at home, one that encourages rapid clean coal development, is also a sensible environmental and energy policy which the U.S. can export abroad.

I will be pleased to answer any questions you have. Again, on behalf of the Clean Coal Technology Coalition I wish to thank you for the opportunity to present these views.

[The prepared statement of Mr. Yamagata follows:]

ABSTRACT OF THE

WRITTEN STATEMENT OF THE CLEAN COAL TECHNOLOGY COALITION

BEFORE THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

JANUARY 24 AND 25, 1990

I. INTRODUCTION:

A. About the Clean Coal Technology Coalition.

This written statement is submitted on behalf of the members of the Clean Coal Technology Coalition, an ad hoc group of electric utilities, equipment suppliers, coal companies, architect-engineering and construction firms, a host of state governments and universities, the National Coal Association, the Edison Electric Institute and the American Mining Congress. The Coalition, which has a total membership of 83, was organized in early 1985 for the specific purpose of encouraging the demonstration, deployment and widespread commercialization of clean coal technologies.

The Coalition has sought to involve the federal government in a partnership with the private sector to advance the use of clean coal technologies that promise the cost-effective production of electric energy from coal while protecting the environment.

B. Specific Issues Addressed in the Statement.

The written statement addresses the following questions:

1. What are clean coal technologies?

2. What are the energy and environmental benefits of developing and commercializing clean coal technologies?

3. How would enactment of S. 1630, as reported by the Environment Committee, impact the development of clean coal technologies? and,

4. What would be the energy policy implications -- based on the impact to the development of clean coal technologies -- of passage of S. 1630?

C. Conclusions and Assertions Made in the Statement.

The ability of the United States to continue to rely on our abundant supplies of coal to provide electric energy under pins a sound national energy policy. The ability of the United States to protect the environment, and to prevent further pollution under pins a sound national environmental policy. To the extent that clean coal technologies are an effective mechanism for achieving pollution prevention, rather than simply pollution control; and to the extent that clean coal technologies are a cost-effective means of producing electric energy from coal, it is in the best interest of our Nation to pursue a course of action that will assure the expedient development, demonstration and widespread commercial deployment of these technologies.

The Coalition believes that the passage of S. 1630 will severely impact the development of clean coal technologies. Further, the provisions in S. 1630 that are intended to encourage the use of clean coal technologies are wholly inadequate, and indeed, represent a retreat from even those modest clean coal technology provisions contained in the President's clean air plan.

Unless S. 1630 is amended to provide adequate time and incentives, and protection from onerous regulatory penalties, for the use of clean coal technologies, the Nation may forfeit the energy and environmental benefits that are to be derived from use of these technologies that can facilitate the continued use of coal in an environmentally acceptable manner. And, the cost to the country in terms of lost industrial competitiveness due to implementation of policies that do not facilitate the use of coal are ominous. Regions of the country expected to have the largest electric rate increases if S. 1630 is enacted are the parts of the country that account for 25% of our Nation's export activity. An increase in electric rates will translate into lost manufacturing jobs, especially in energy intensive industries, such as aluminum and will cause such industries to move off shore and be permanently lost.

D. Suggested Modifications to S. 1630.

At a minimum, the Senate should act to restore those clean coal technology provisions included in the President's clean air plan that were not included in the Senate Environment and Public Works reported bill, S. 1630. These provisions include a five year, FERC-related incentives program and an exemption from certain environmental reviews for those clean coal technologies eligible for the extension in the Phase II deadline or those clean coal projects selected under the on-going DOE program or currently supported by the EPA.

In addition, the Senate should consider expanding the list of clean coal technologies eligible for the Phase II extension of time beyond those so-called "repowering" clean coal technologies currently listed in S. 1630.

Without at least the President's provisions for clean coal technologies, further development of these technologies is doubtful, but even if S. 1630 were amended so as to reinstate the President's clean coal provisions, the legislation would fall short in efforts to encourage the commercialization and widespread use of clean coal technologies.

WRITTEN STATEMENT OF BEN YAMAGATA
ON BEHALF OF THE CLEAN COAL TECHNOLOGY COALITION

BEFORE THE

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
UNITED STATES SENATE

REGARDING THE IMPACT OF ACID RAIN CONTROL LEGISLATION
UPON THE DEVELOPMENT OF CLEAN COAL TECHNOLOGIES

JANUARY 24 AND 25, 1990

I. INTRODUCTION:

This written statement is submitted on behalf of the Clean Coal Technology Coalition which is an ad hoc group of electric utilities, equipment suppliers, coal companies, architect-engineering and construction firms, a host of state governments and universities, the National Coal Association, the Edison Electric Institute and the American Mining Congress. The Coalition, which has a total membership of 83, was organized in early 1985 for the specific purpose of encouraging the demonstration, deployment and widespread commercialization of clean coal technologies. (See: Attachment 1 for a complete listing of the Coalition's membership.)

This statement addresses the energy policy implications of the acid rain control title of S. 1630, the Clean Air Restoration and Standards Attainment Act of 1989. More specificially, the Coalition has been asked to discuss the impact that S. 1630, as reported by the Senate Environment and Public Works Committee, could have on the continued and expeditious development of clean coal technologies.

The following questions are addressed in this submittal:

1. What are clean coal technologies?
2. What are the energy and environmental benefits of developing and commercializing clean coal technologies?
3. How would enactment of S. 1630, as reported by the Environment and Public Works Committee, impact the development of clean coal technologies? and,
4. What are the energy policy implications -- based on the impact to the development of clean coal technologies -- of S. 1630?

II. WHAT ARE CLEAN COAL TECHNOLOGIES?

Clean coal technology refers to a suite of emerging coal-based technologies that, if developed, offer significant potential for improvement over current means to generate useful energy from coal more efficiently and to cost-effectively control emissions that result from using coal. These technologies are installed or utilized prior to the combustion of coal, during the combustion process, or after combustion has occurred. In addition, a number of the technologies actually convert the coal into another usable energy form such as a coal-derived gas or liquid. (See: Attachment 2 for a general description of clean coal technologies.)

Clean coal technologies are also grouped into two categories depending upon their purpose: (1) retrofit technologies, which can be applied at existing powerplant units for the specific purpose of reducing emissions, and (2) repowering technologies, which replace a portion of an original unit in order to increase capacity and simultaneously reduce emissions. These same repowering technologies can also be utilized in new, "greenfield" powerplants to generate electricity and to also control emissions more efficiently and cost-effectively than current pulverized coal technology fitted with a wet limestone scrubber.

Some retrofit technologies, like advanced scrubbers, achieve high percentages of sulfur dioxide removal while also controlling nitrogen oxide emissions and avoiding the production of the wet sludge waste by-product of conventional scrubbers. Other retrofit technologies do not achieve the 90%, or more, sulfur emission reductions (unless used in combination with each other) that can be attained by use of advanced scrubbers. However, such technologies do offer a means of reducing emissions by 50-70% at costs projected to be significantly less than installing conventional scrubbers. Also, a number of these technologies are capable of simultaneously controlling NOx emissions.

Retrofit technologies are important as an alternative to more costly scrubbers and, if commercialized in time, could provide significant cost-saving advantages if relied upon to meet requirements of any acid rain control legislation, like S. 1630, that may be enacted.

Repowering technologies are a means of pollution control which meet or exceed current Clean Air Act requirements. In addition, these technologies if installed on existing power plants, are able to increase the capacity of those plants. Installation at existing plants might result in increasing the electricity output of the plant by 15% to 150%, while avoiding siting issues and other impediments associated with new power plant construction. (See: Attachment 3 for a listing of retrofit and repowering technologies.)

The importance of encouraging the development of clean coal technologies is three-fold:

First: Clean coal technologies offer a means by which to control emissions from the use of coal in an efficient and cost-effective manner;

Second: Clean coal technologies will enable utilities and others to continue to use coal to meet growing energy requirements in the 1990's and beyond.

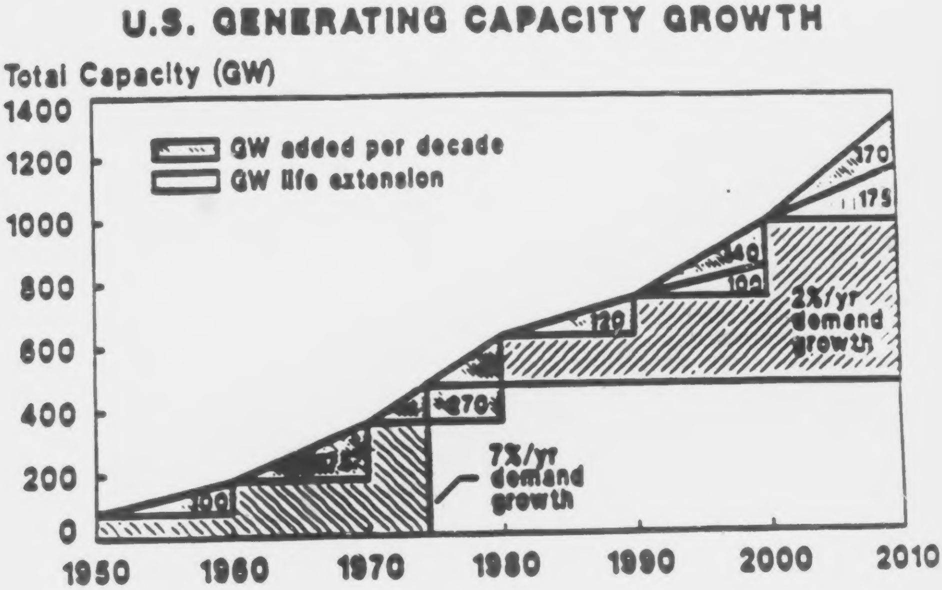
Third: Clean coal technologies will be used by other countries to meet their growing energy requirements; successful development in the U.S. will mean significant new markets for export of American technology and know-how.

III. WHAT ARE THE ENERGY AND ENVIRONMENTAL BENEFITS OF DEVELOPING AND COMMERCIALIZING CLEAN COAL TECHNOLOGIES?

A. Projected Increases in U.S. Electric Demand and the Role of Coal in Meeting that Demand:

Coal currently supplies the fuel for more than one-half of the electricity generated in this country. Coal-burning power plants (including lignite) account for 43.5% of total operable capacity (as of year-end 1988) and over 56% of actual power generated. America's recoverable coal reserves, which the Department of Energy places at 268 billion tons, are sufficient -- at even double today's rates of production -- to last this century, the next century and a significant portion of the century to follow. Without dispute, the U.S. has very significant supplies of coal to meet almost any level of increased demand. The challenge in whether, even in light of this domestic abundance, coal can be relied upon to meet projected demands for increased electrical energy.

Estimates vary as to the amount of new and replacement capacity that will be needed in the 1990's and beyond to power a growing economy. Electricity growth predicted by the Electric Power Research Institute (EPRI) and depicted in the figure below, indicate a need for as much as 140,000 megawatts of new capacity.



The Energy Information Administration's (EIA) 1989 Annual Outlook for U.S. Electric Power, appears to corroborate these estimates by projecting the need for 110 gigawatts (one gigawatt = 1,000 megawatts) of new capacity additions by electric utilities and 28 gigawatts of non-utility capacity additions by the year 2000. Fifty gigawatts of this new capacity, according to the EIA report, are expected to be fueled by coal.

B. Limitations of Current Coal-Based Technologies:

The utility industry is faced with two realities about the technologies currently available to use coal and to control air emissions from the use of coal.

First, conventional pulverized coal units are the only available technology commercially proven for the generation of large amounts of electricity from coal. Because pulverized coal units depend upon economies of scale, they are relatively large units requiring long construction periods and large capital investments. This technology is near the end of its development potential.

Second, the utility industry has limited existing options to control SO2 emissions from coal use -- coal cleaning, conventional scrubbers and coal switching.

Each of these methods for controlling coal-derived air pollutants has disadvantages. For example, conventional coal cleaning has only a limited ability to remove sulfur, typically only 10 to 30 percent of the total sulfur in coal. Conventional scrubbers are costly and can only be retrofitted to an existing unit if sufficient space at the power plant site is available. In addition, conventional scrubbers use a portion of the electricity produced in the power plant to operate, thus lowering efficiency. Also, the typical flue gas desulfurization system today produces a wet waste product that requires a significant area for disposal. Coal switching could become costly if a significant shift to low sulfur coal occurs and the demand for such coal exceeds the supply. Use of lower sulfur coal in units originally designed for higher sulfur coals can also result in boiler derating whereby output is lowered, due to coal characteristics which do not meet or are in conflict with the design specifications of a particular boiler. Also, unless designed for low sulfur coal use, the operation of electrostatic precipitators could be adversely affected and could create problems of particulate compliance.

These limitations with regard to the current means to control air pollutants are aggravated by the wide diversity of the nation's utility boiler population in terms of boiler designs, ages, sizes and configurations, as well as the type of coal consumed.

In the face of these realities, the electric utility industry must change its technological base for electricity generation derived from coal. New power generation options are required which can --

- meet increasingly-stringent siting and environmental standards without sacrificing productivity;
- be rapidly constructed in modular fashion while retaining acceptable economies over a wide range of unit sizes to better match uncertain demand growth; and,
- utilize a variety of coals in a single design.

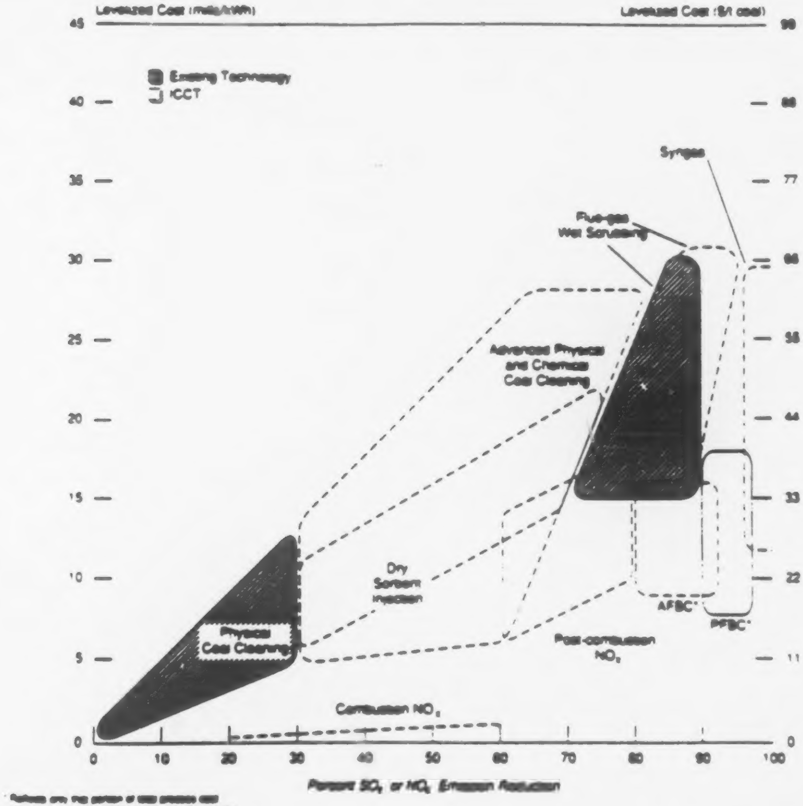
In the context of considering legislation to further control emissions of SO2 or NOx, consideration should be given by this Committee to the continued role of coal in meeting our nation's energy requirements. It is vitally important to understand that energy supply and our nation's economic security are closely tied to the use of our most abundant and secure fossil fuel resource -- coal. Clean coal technologies can serve as the bridge in filling any gap between increased coal utilization to achieve energy (and economic) security and sustained (and enhanced) environmental quality. Given the promise of clean coal technologies, if control legislation like S. 1630 is ultimately enacted, it must include adequate time and incentives to encourage the development of these technologies, thereby better assuring a role for coal in meeting our energy needs (see: attachment 4 for additional discussion on the role of other energy resources in fulfilling U.S. domestic energy needs).

C. The Role of Clean Coal Technologies in Making Coal More Environmentally and Economically Attractive:

Coal utilization must be made compatible with environmental protection. This means that emissions reductions, as would be required under S. 1630, and cost-effective electricity generation must be achieved concurrently and not pitted one against the other. Clean coal technologies are the key to that compatibility. Successful development and use of emerging clean coal technologies can provide a win for ratepayers by moderating increases in electric rates and also a win for the environment.

From the standpoint of cost effectiveness and ability to control emissions, clean coal technologies promise to be far superior to currently available methods of control. Figure 1 compares the costs and effectiveness of emissions control of the various conventional and new technologies. (See also: Attachment 5 which compares the cost and efficiency of various technologies now under development.)

Cost-effectiveness of Clean Coal Options Versus Existing Technology



SOURCE: Electric Power Research Institute

Source: National Coal Council Report, November 1988

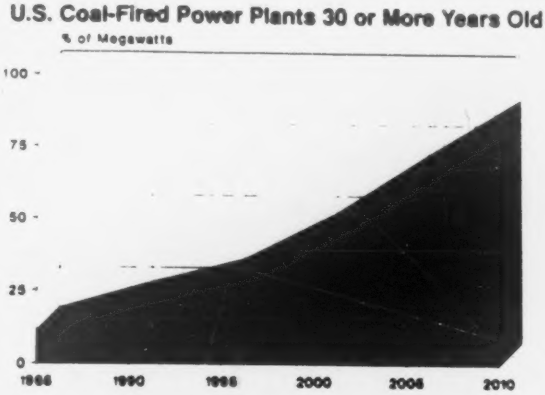
Among the many technical and cost advantages of clean coal technologies are the following:

- reduction of sulfur dioxide (SO2) emissions in a more cost effective manner than currently-available technology;
- simultaneous reduction in some cases of both SO2 and NOx emissions (conventional scrubbers only reduce SO2 emissions);
- attainment of required environmental control at lower capital and operating and maintenance costs than current technology;
- utilization of the widest range of coals, from low to high sulfur coals;
- modularity in some cases, which means units can be sized more closely to match load growth and can take advantage of the economies of shop assembly and pre-fabrications, thereby shortening construction time and cost;
- cost savings of 10 to 20 percent depending upon plant-size for new applications when compared to conventional generation technology;
- use of existing plants and plant sites in retrofit and repowering applications, thereby avoiding premature plant retirements or replacement with other fuels;
- projected savings of 10 to 30 percent over conventional technologies when retrofitting existing facilities with clean coal retrofit technologies; and
- increased efficiency in coal use which decreases emissions of CO2, a greenhouse gas per unit of energy produced.

Furthermore, success in the development of these technologies may preserve American mining jobs, will better ensure U.S. industrial competitiveness, and could expand the trade of American coal and technological know-how.

D. Potential Domestic and Foreign Markets for Clean Coal Technologies:

According to the Department of Energy, halfway through this decade, more than one-half of the current population of boilers in the U.S. will be at least 30 years old; and, by the turn of the century, the percentage of aged boilers will rise even more sharply to about 44%. At the same time, as noted above, there are projected dramatic increases in the demand for electricity in this country.



By the year 2000, 44% of the nation's coal-fired power capacity will be 30 years old or older. The aging nature of U.S. power plants could raise reliability and supply problems unless they can be "repowered" with new, more efficient clean coal technology.

The aging U.S. boiler population and the need for new capacity could create a huge domestic market for clean coal technologies since these technologies -- particularly the repowering technologies -- offer significant benefits over conventional technologies. Repowering technologies, for example, could extend the life of a boiler by 20 to 30 years and could potentially boost the plant's output by as much as 150%. According to DOE, the effect would be the same as building two or more power plants at the same site while reducing sulfur emissions by as much as 99% and NOx emissions by 40%.

Furthermore, the National Coal Council, in its recent report entitled Innovative Clean Coal Technology Deployment (November 1988), estimated that the United States could become a dominant player in a world-wide clean coal technology market valued at $50 billion per year by 2000 and $70 billion per year by 2010.

The U.S. has historically been the world leader in coal technology. The majority of coal-fired power plants in the free world and in the developing countries have relied on technology supplied by, or licensed from, U.S. manufacturers. The Integrated Gasification Combined Cycle plant at Coolwater has been viewed as the most successful energy prototype developed during the last energy crunch of the late 1970's and early 1980's. Also, the U.S. can maintain the lead in the development of other technologies such as magnetohydrodynamics (MHD) and coal-based fuel cells both hold great promise in achieving increased conversion efficiencies and very low emissions. However, our technical leadership in coal-based technologies is increasingly challenged. The Japanese are the world leaders in the development of both combustion and post-combustion NOx control technology. The Europeans are leaders in fluidized bed technology. In other words, if our energy and environmental policies lose focus on the strategic importance of coal and the technologies for its use we also risk losing international markets potentially worth billions of dollars in trade. And, we risk the loss of domestic markets to foreign manufacturers who are rapidly gaining superiority and leadership in the development of many clean coal technologies.

IV. HOW WOULD ENACTMENT OF S. 1630, AS REPORTED BY THE ENVIRONMENT COMMITTEE, IMPACT THE DEVELOPMENT OF CLEAN COAL TECHNOLOGIES?

A. Projected Commercial Availability of Emerging Clean Coal Technologies:

S. 1630, which requires emissions reductions by certain dates, will impede the use of new technologies unless such technologies are available and commercially proven in time to plan for and then to meet the compliance deadlines. (The deadline for Phase I compliance is January 1, 1995, and for Phase II compliance the deadline is January 1, 2000, the technologies must be available several years [3 to 5] in advance to allow for design, permitting, construction and initial testing/shake down.)

Only after successful demonstration and deployment will a particular clean coal technology be considered an option for achieving reductions of atmospheric pollutants; even then, successful demonstration and deployment does not mean that the technology will be immediately and widely incorporated into the nation's electric generation base thereby achieving significant reductions. The utility industry -- each utility -- will proceed very carefully when applying a new technology. This means that for any given utility, a successfully-demonstrated clean coal technology will be applied first to one unit and then another before being incorporated into an entire system. This market penetration scenario will be replicated many times over throughout the entire utility industry.

After achieving commercial maturity, introduction of clean coal technologies into the entire generation base could easily take a decade or more. Among those factors which will govern the time necessary for introduction are: time to evaluate the technology's performance and to decide to use it on additional units; time to site such projects; time to complete permitting and regulatory approvals, including approvals by utility rate regulatory agencies; and, time to place orders and receive equipment from manufacturers of the clean coal technology.

Therefore, the time required to insure commercial maturity and to achieve introduction and widespread use must be considered if the Congress chooses to impose stricter emission requirements while also continuing policies and programs designed to encourage clean coal technologies. This requirement for sufficient amounts of time, of course, does not mean that clean coal technologies should be exempt from existing local, state or federal requirements intended to protect the environment.

Attached to this statement (see: Attachment 6) is an estimate by the Coalition as to when the various clean coal technologies may be ready for commercial use. In particular, it should be noted that industry will require most of the 1990's to demonstrate, deploy and bring to commercial readiness clean coal technologies. These estimated dates do not factor in the disincentives to demonstrating new technologies if industry must also plan and execute programs to meet reduction requirements at the same time.

Unless adequate time and flexibility in compliance are provided in control legislation, a utility will probably comply with mandated reduction requirements by switching fuel sources, shutting down power plants prematurely or retrofitting conventional scrubbers. Emerging clean coal technologies, given current levels of development and associated risks, will be a very limited option.

Not only will clean coal technologies be of limited use in meeting reduction requirements, but also the on-going clean coal technology demonstration program to which Congress will have appropriated more than $2.5 billion may be jeopardized. It is doubtful that industry would use limited resources to cost-share in the demonstration of new technologies when faced concurrently with requirements for massive emission reductions. (Participants in the on-going DOE clean coal program are required to provide at least fifty percent of the costs of a clean coal demonstration.) If these demonstrations are delayed or not conducted, then clean coal technologies are not likely to become a preferred option of industry and the use of coal will be further jeopardized.

B. Clean Coal Technology Provisions of S. 1630:

S. 1630 contains a few of the provisions for clean coal technologies recommended by President Bush in his Clean Air Act proposal. However, several of the modest but important provisions of the Administration's proposal were not included in the bill reported out of the Environment and Public Works Committee. S. 1630 contains a four-year extension, until

December 31, 2003, for a limited number of "repowering" technologies. The President's clean air proposal contained -- in addition to the above provisions -- a Federal Energy Regulatory Commission (FERC) initiated, five year demonstration program to provide certain, enumerated rate regulatory incentives for no more than four projects per class of clean coal technology. The proposal also clarified the application of the EPA's "WEPCo" ruling on clean coal technology projects (see: attachment 7).

Exemptions from certain provisions of the current Clean Air Act, as addressed in the WEPCo decision, are particularly important. Specifically, the President's proposal has recognized that the risks of new technology application are too great if those who first undertake the demonstration and early appliation of these technologies are also confronted with even more stringent environmental requirements if the technology does not ultimately reach anticipated levels of emissions control, is removed after the demonstration is completed, or does not achieve the same emissions reductions as current, but more expensive, control technologies. In each case, the utlitity may be confronted with even more stringent environmental standards on a particular unit for having taken the voluntary action of demonstrating or utilizing a new clean coal technology. Few, if any, utilities can take such a risk.

C. Inadequacy of Clean Coal Provisions Included in the Administration's Proposed Clean Air Act Amendments:

Without at least the President's provisions for clean coal technologies, further development of these technologies is doubtful, but even if S. 1630 were amended so as to reinstate the President's clean coal provisions, the legislation falls short in efforts to encourage the commercialization and widespread use of clean coal technologies.

First, the number of clean coal technologies which are eligible for the Phase II extension of time is unnecessarily limited (only so-called "repowering" technologies are eligible; "retrofit" clean coal technologies, whether precombustion or post combustion are not eligible).

Second, the FERC-related rate regulatory incentives are limited to a modest 5 year demonstration program in which only four projects in each clean coal technology class would be eligible for the regulatory incentives. Also, exemptions from "WEPCo" review apply only to clean coal projects that qualify for the extension for repowered sources or that have been selected under on-going demonstration programs. Such exemptions will not apply to those clean coal projects, including those that would use clean coal retrofit technologies, that may be undertaken by industry on its own without government support.

V. WHAT WOULD BE THE ENERGY POLICY IMPLICATIONS -- BASED ON THE IMPACT TO THE DEVELOPMENT OF CLEAN COAL TECHNOLOGIES -- OF PASSAGE OF S. 1630?

A. Energy Policy Implications of Delays in the Development of Clean Coal Technologies:

Coal can and should play an integral role in helping the Nation to meet the expected growth in electric demand between now and the end of the century. But, to the extent that S. 1630 increases the costs associated with using coal to meet these anticipated new capacity requirements, and to the extent that S. 1630 severely impedes the utility industry's ability to develop and use clean coal technologies (which offer a means of utilizing coal more cost-effectively and more cleanly); the energy policy implications of S. 1630 are dire.

Further, the costs to the country, in terms of lost industrial competitiveness due to an energy policy that doesn't facilitate coal use, are ominous. According to the National Coal Association (NCA), industries in the midwest and the south -- the regions of the country projected to have the largest increases in electric rates if S. 1630 is enacted -- account for fully 25% of our Nation's export activity. This increase in rates would translate into lost manufacturing jobs and the NCA projects that energy intensive industries, such as aluminum, would move off shore and be permanently lost.

Clean coal technologies, as noted above, can help to moderate electric rate increases by providing more cost-effective energy production and pollution prevention. Therefore, these technologies could help lessen the rate-shock that the mid-west is likely to experience if S. 1630 is enacted. But, since the provisions of S. 1630 do not encourage -- and indeed tend to negate -- the development of clean coal technologies, they may not play a role in mitigating the rate impacts of the control program.

Unless S. 1630 is amended to provide adequate time and incentives, and to provide protection from time-consuming regulatory reviews arising from the use of these technologies, the Nation will forfeit the important energy policy benefits -- as well as the important environmental benefits -- associated with these technologies.

B. Suggested Modifications to S. 1630:

At a minimum, the Senate should act to restore those clean coal technology provisions included in the President's plan, but not included as part of S. 1630 as reported by the Environment and Public Works Committee. These provisions include:

1. a Federal Energy Regulatory Commission initiated five year demonstration program to provide certain, enumerated rate regulatory incentives for no more than four projects per class of clean coal technology, and

2. an exemption from certain environmental reviews for those clean coal technologies eligible for the repowering extension or those clean coal projects selected under the on-going DOE program or currently supported by the EPA.

President Bush and Members of Congress have expressed strong support for the continued development of clean coal technologies and indicated their intent to ensure that these technologies remain an integral part of any clean air plan. To ensure that a wide array of these new technologies are developed and widely used, S. 1630, should be amended further to ensure that the following clean coal objectives are attained:

first: to support and encourage ALL clean coal technologies not just designated "repowering" technologies;

second: to acquire adequate engineering data so that industry and utility regulatory commissions will then have confidence that the technologies will meet commercial needs (such data can only be obtained through the replication of successfully demonstrated technologies in a limited number of commercial applications and by giving industry a sufficient amount of time during which to gain that confidence);

third: to encourage the accelerated commercialization of those clean coal technologies which by means of lowered capital and operating costs -- when compared to currently available means of reducing emissions -- will moderate rate impacts on electric consumers and, in turn, benefit the economy and U.S. competitiveness; and

fourth: to enhance U.S. energy security by continuing and increasing the use of all domestic coal resources in a manner that is consistent with national environmental goals.

To best assure the continued development of clean coal technologies S. 1630 should be amended as follows:

1. The definition of "clean coal technology" found in section 402 (1) should be expanded to include retrofit, as well as repowering technologies, making the full suite of clean coal technologies eligible for the compliance deadline extension.

2. The FERC initiated program, included in the President's proposal, should be restored and expanded to include any clean coal technology project which has received government funding pursuant to the DOE clean coal technology demonstration program, any EPA-supported clean coal project or any designated clean coal technology eligible for the incentives provided in section 409 of S. 1630, as amended.

3. The legislation must also include provisions that grant greater flexibility in achieving required emission reductions where it is intended that a clean coal technology will be used. To achieve this flexibility the following changes should be made:

   a. Where a user chooses to install a designated clean coal technology, as provided in section 409, that user should be afforded the choice of replacing the existing capacity with a new clean coal, "greenfield" facility instead of incorporating the clean coal technology into that existing unit.

   b. Where a utility chooses to install a designated clean coal technology but it is subsequently determined by the EPA and the user that the clean coal technology will not be feasible, then the user should be permitted an extension of time in order to comply with Phase II requirements by whatever acceptable means are then available.

   c. By December 31, 1992, the DOE, in consultation with the EPA, would publish a list of clean coal technologies that will be eligible for the Phase II extension and incentives.

4. Where a user utilizes a designated clean coal technology to comply with the requirements of Phase II, the compliance date should be extended to the end of calendar year 2005.

The purpose of these suggested changes is to ensure that the U.S. receives the full environmental and energy-related benefits of the on-going multi-billion dollar clean coal technology demonstration program. This can be achieved if --

- o the incentives contained in the President's proposal legislation are made available to ALL clean coal technologies now being developed, thereby enabling industry to make the most cost-effective choices from the full suite of developing CCT's and

- o industry is given FLEXIBILITY in using a CCT to meet emission requirements and is provided assurance that, if a clean coal technology is utilized, avenues of relief will be available to obtain time to assure the reliable operation of the CCT, or to comply by other methods of emissions control if the technology fails completely.

VII. CONCLUSION:

The ability of the United States to continue to rely on our abundant supplies of coal to provide electric energy under pins a sound national energy policy. The ability of the United States to protect the environment, and to prevent further pollution under pins a sound national environmental policy. To the extent that clean coal technologies are an effective mechanism for achieving pollution prevention, rather than simply pollution control; and to the extent that clean coal technologies are a cost-effective means of producing electric energy from coal, it is in the best interest of our Nation to pursue a course of action that will assure the expedient development, demonstration and widespread commercial deployment of these technologies.

The Coalition believes that S. 1630, as reported out of the Senate Environment and Public Works Committee, will severely impact the development of clean coal technologies. Further, the provisions in S. 1630 that are intended to encourage the use of clean coal technologies are wholly inadequate, and indeed, represent a retreat from even those modest clean coal technology provisions contained in the President's clean air plan.

Unless S. 1630 is amended to provide adequate time and incentives, and protection from regulatory penalties for those early users of clean coal technologies, the Nation may forfeit the energy and environmental policy benefits that are to be derived from development and widespread use of these technologies.

Attachment 1

CLEAN COAL TECHNOLOGY COALITION

MEMBERSHIP

January 19, 1990

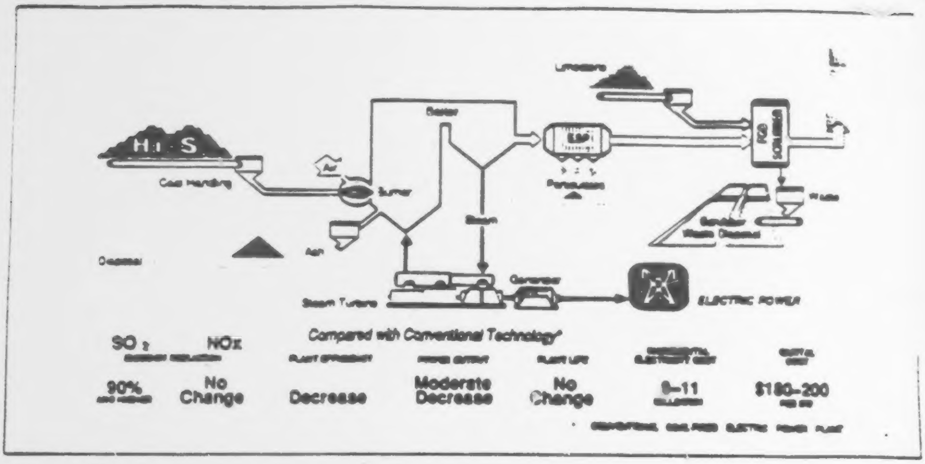
A.T. Massey Coal Company, Inc.
Alabama Coal Association
Allison Gas Turbine Division, General Motors Corporation
AMAX Coal Company
American Electric Power Service Corporation
American Mining Congress
Arch Mineral Corporation
Ashland Coal, Inc.
Babcock & Wilcox
Baltimore Gas & Electric Company
Bechtel Power Corporation
Bethlehem Steel Corporation
Brigham Young University
Carbon Fuels Corporation
Carolina Power & Light Company
Centerior Energy
Central Illinois Public Service Company
Cincinnati Gas & Electric Company
Combustion Engineering, Inc.
Combustion Power
Consolidation Coal Company
Cyprus Coal Company
Deutsche Babcock Werke, AG
Duke Power Company
Edison Electric Institute
Florida Power Corporation/Electric Fuels Corporation
Fluor Corporation
General Electric Company
General Public Utilities, Inc.
Geneva Steel
Illinois Power Company
Indiana University
Indianapolis Power & Light
Jersey Central Power & Light Company
Madison Gas and Electric Company
Marietta Coal Co.
Metropolitan Edison Company
MHD Development Corporation
Montana State University
National Coal Association
National Lime Association

NEOS Corporation
Northern Indiana Public Service Co. (NIPSCO)
Ohio Edison
Ohio Mining and Reclamation Association
Ohio Clean Fuels, Inc.
Oklahoma Gas & Electric Company
Orange and Rockland Utilities, Inc.
Passamaquoddy Technology
Peabody Holding Company, Inc.
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Pittsburg & Midway Coal Mining Co.
Public Service Company of Colorado
Public Service Company of Indiana
Roberts and Schaefer Company
San Diego Gas & Electric
South East Coal Company
Southern Company Services
Southern Illinois University at Carbondale
Southern Indiana Gas & Electric Company
Stone & Webster Engineering Corporation
Texaco, Inc.
The Commonwealth of Kentucky
The State of Alabama
The State of Colorado
The State of Illinois
The State of Indiana
The State of Ohio
The State of Texas
The State of West Virginia
TransAlta Utilities Corporation
Union Electric Company
United Coal Company
School of Mines and Energy Development, University of Alabama
University of Missouri-Columbia
University of Montana
University of Southern Indiana
University of Tennessee
University of Wyoming
Western Research Institute
West Virginia University
Wisconsin Power & Light Company
Wisconsin Public Service Corporation

Attachment 1

Coal's Fuel Chain

Today's flue gas scrubbers....


Limestone
Boiler
ESP
FGD Scrubber
H S
Coal Handling
Air
Burner
Particulates
Waste
Steam
Scrubber Waste Disposal
Disposal
Ash
Generator
Steam Turbine
ELECTRIC POWER
Compared with Conventional Technology*
SO 2
NOx
90%
No Change
Decrease
Moderate Decrease
No Change
8–11
$180–200

The 1970 Clean Air Act required that coal-fired power plants emit no more than 1.2 pounds of SO_2 emissions per million Btu of coal consumed. Many utilities could meet the standard by burning low-sulfur coal. In 1977 Congress amended the Act, retaining the original emissions cap but adding a further requirement that all plants built or altered after September 18, 1978, reduce sulfur emissions by 70-90%. The percentage reduction, in effect, mandated the use of scrubbers on all new coal-fired power plants (since the scrubber was the only commercial technology capable of achieving this level of pollution control). It also removed the market advantage of using low-sulfur coal.

Two types of conventional scrubbers exist. Both remove only SO_2 (not NOx).

> **Wet scrubber** - Coal combustion gases are typically sprayed with a slurry made up of water and an alkaline reagent, usually limestone. The SO_2 in the flue gas reacts chemically with the reagent forming calcium sulfite and calcium sulfate in the form of a wet sludge (having the consistency of toothpaste). Over its lifetime, a conventional 500-megawatt coal-fired power plant will produce enough sludge to fill a 500-acre disposal pond to a depth of 40 feet. Wet scrubbers are costly to install – costing as much as $250 per kilowatt capacity – and to operate. They consume 5-8 percent of the plant's thermal energy to run pumps, fans and a flue gas reheat system. They require large amounts of water, 500-2500 gallons per minute for a 500 megawatt unit.
>
> **Dry scrubber** (or spray dryer) - The reagent slurry is injected into the scrubber in a finely atomized form. The droplets evaporate in the hot gas, leaving only dry particles for collection. Although simpler in concept, the dry scrubber has not been used successfully on high-sulfur coal due largely to the increased amounts of costly reagents required to obtain 90 percent SO_2 reduction.

Conventional Technology

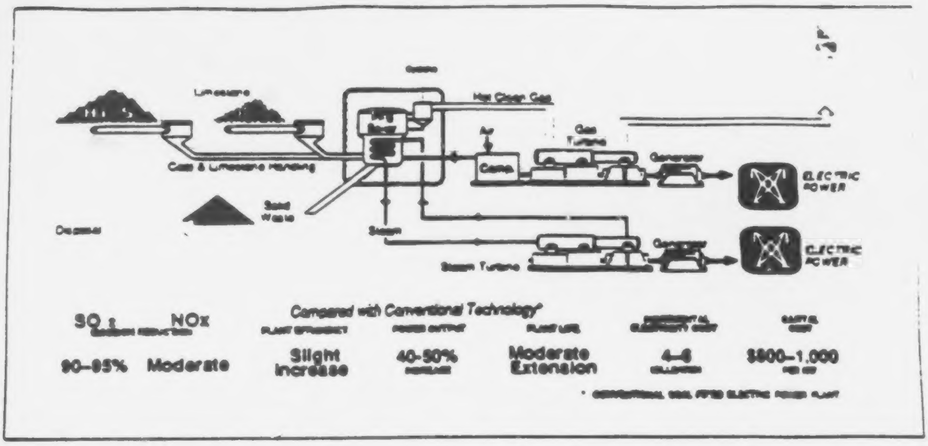
A quick review....

Clean Coal Technology

At each point in the fuel chain....

② Clean Coal Technologies...

Advanced Combustion Processes


Limestone
Hot Clean Gas
Air
Gas Turbine
Comp.
Coal & Limestone Handling
Solid Waste
Disposal
Steam
Steam Turbine
Generator
ELECTRIC POWER
ELECTRIC POWER
SO2
NOx
Compared with Conventional Technology*
90–95%
Moderate
Slight Increase
40-50%
Moderate Extension
4–6
$800–1,000

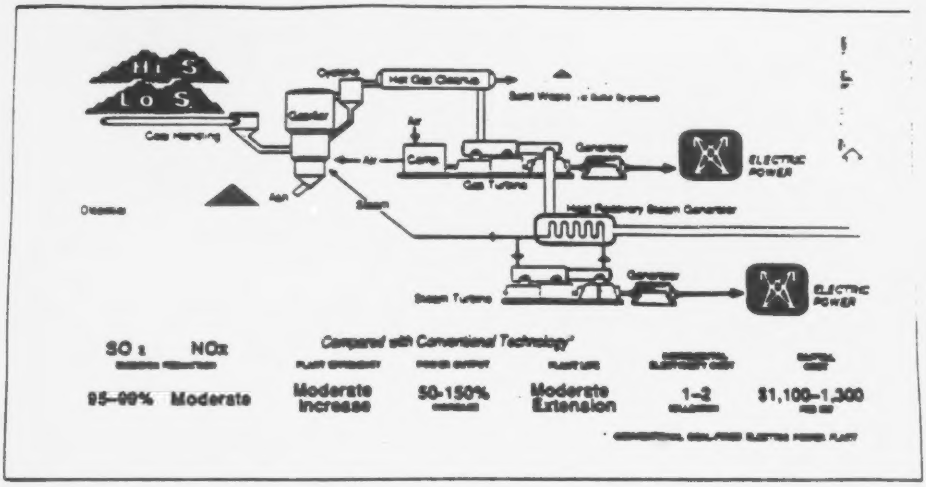
Fluidized bed combustion – A fluidized bed combustor burns coal particles while they are "floating" in a "bed" suspended by upward-blowing air jets (rather than being swept rapidly through the combustion zone as in a conventional pulverized coal boiler). When limestone is added to the bed, it acts as a chemical "sponge," absorbing 90-95% of the SO_2 released from the burning coal. The reaction produces a dry, solid waste that can be removed with the ash. Fluidized bed combustors burn at much lower temperatures than conventional combustors – typically 1400-1600 degrees F (rather than the 3000 degrees of pulverized coal boilers) – which inhibits the formation of nitrogen oxides. They can be designed to operate at atmospheric pressure or under pressurized conditions (typically 6-16 times atmospheric pressure).

Advanced, non-fluidizing combustors – These combustors can be "slagging," meaning that they reject ash by converting it into a molten slag, or they can employ one of several innovative concepts such as pulsed combustion, explosive comminution, or wet oxidation of coal. In the slagging combustor (the most technologically mature approach), coal particles or slurry droplets are injected radially from a central point while the air is fed around the periphery of the combustion chamber. The continuous movement of air across the burning coal provides more rapid and efficient combustion. Slag is expelled along the combustor's outer walls, while SO_2 emissions can be reduced by 50-90% by injecting limestone into the combustion chamber. By positioning air injection ports to stage the combustion process, NOx can be reduced by 50-70%.

Limestone Injection Multistage Burner – In this device, limestone is injected into the combustion gases of a burner operating at a temperature that produces dry ash rather than slag. Ash and sulfur are captured downstream by a particulate control device. SO_2 emissions can be reduced by 50-60% and, by staging the combustion process, NOx emissions can be cut by 50-70%.

④ Clean Coal Technologies...

Conversion Processes


Hi S
Lo S
Coal Handling
Cyclone
Gasifier
Hot Gas Cleanup
Solid Waste
Air
Comp
Gas Turbine
Generator
ELECTRIC POWER
Ash
Disposal
Steam
Heat Recovery Steam Generator
Steam Turbine
Generator
ELECTRIC POWER
SO 2
NOx
95–99%
Moderate
Compared with Conventional Technology*
Moderate Increase
50-150%
Moderate Extension
1–2
$1,100–1,300

These techniques bypass or eliminate the coal combustion process altogether. Instead coal is converted into a gas or liquid form which is then cleaned before it is used:

Integrated gasification combined cycle – So-named because it links coal gasifiers to a combined-cycle arrangement of gas and steam turbines. A combined cycle configuration is a highly efficient power generating technique – efficiencies are in the range of 40-45%. It retains its performance advantages over a large range of modular scales beginning as small as 100 megawatts.

In contrast to combustion, gasifying coal does not release sulfur as SO_2. Rather the sulfur is converted almost entirely to hydrogen sulfide (H_2S). Techniques can remove 99% or more of the H_2S in a gas stream; however, conventional approaches operate at relatively low temperatures (less than 200 degrees F). This requires the hot gases exiting the coal gasifier to be cooled, an expensive step that lowers plant efficiency. New techniques achieve the same level of sulfur reductions at temperatures of 1000 degrees F or more, closer to the temperature of the gas exiting the gasifier. Hot gas cleanup minimizes the cooling step and boosts efficiencies, thus lowering power costs.

Coal-oil coprocessing – In this concept, coal is slurried with the heavy residual oil that is often a waste product of refineries. The coal-resid mixture is then processed in an advanced petroleum "cracking" unit. The presence of the resid eliminates or reduces the need for internal oil recycling that adds considerably to the expense of coal-only synthetic fuel processes. As a result, there is a much higher throughput of product per unit of capital investment. The liquid product can be cleaned of its sulfur and ash impurities much like conventional petroleum.

Attachment 3

DEFINITIONS OF REPOWERING AND RETROFIT TECHNOLOGIES*

REPOWERING TECHNOLOGIES are clean coal technologies that replace a significant portion of an existing power plant and often increase electric generation capacity while reducing emissions. While repowering technologies require significant capital investment, generally the increased power output offsets most of the capital cost. In comparison to conventional emissions control technologies, repowering technologies are capable of meeting new source performance standards for SO2 emissions and improve NOx emissions reductions. Also, repowering technologies offer improved waste control characteristics.

RETROFIT TECHNOLOGIES are clean coal technologies that can be used on existing powerplants and are primarily used to reduce emissions. These technologies include advanced coal cleaning technologies as well as technologies that can be integrated at the power plant. Retrofit technologies that can be integrated at the powerplant offer the advantage that they can control NOx emissions as well as SO2 emissions, something that conventional emissions control technologies cannot do. Generally, retrofit technologies add fuel cost or cause losses in generation efficiency, because energy is required to operate them. However, retrofit technologies expand the range of coal types for which emissions can be cost-effectively controlled and are not as space- or site-limited as conventional emissions control technologies.

* Definitions derived from America's Clean Coal Commitment.

What Are Clean Coal Technologies?

Advanced Coal-Based Systems For:

- Power Generation
  - Improved Economics
  - Improved Thermal Efficiencies
  - Modular Construction
  - Improved Environmental Performance
  - Capable of Repowering Existing Facilities
  - Can Use Variety of Coals
- Pollution Control
  - Control SO_2 and NO_x
  - Improved Economics
  - Retrofit and New Source Applications
  - Improved Waste Characteristics
- Other Uses
  - Produce Coal-Based Fuels to Replace Oil or Gas
  - Use Coal in Industrial, Commercial and Residential Sectors

Repowering Technologies

Fluidized Bed Combustion

Atmospheric
- Circulating Bed
- Bubbling Bed

Pressurized
- Circulating Bed
- Bubbling Bed

Hybrid Designs
- Bubbling-Circulating Bed
- Coal Pyrolyzer/Fluid Bed

Gasification-Based

Gasifier Types
- Fixed Bed
- Fluid Bed
- Entrained Flow
- Rotary Kiln-type

Combinations
- Gasification w/Pyrolyzation
- Gasification w/Once-Through Methanol Production

Gas Cleanup systems
- Conventional "Cool" Gas Cleanup
- Zinc Ferrite Hot Gas Cleanup
- Ceramic Filter Cleanup
- In-situ Desulfurization

Advanced Options

Gasification w/Fuel Cell

Magnetohydrodynamics

Direct Coal-Fired Turbines

Retrofit Technologies

Pre-Combustion Cleaning

Physical
- Fine Grinding (micronization)
- Advanced Froth Flotation
- Heavy Media Cyclones
- Micronization w/Limestone
- Microbubble Flotation

Physiochemical
- Molten Caustic Leaching
- Organic Solvent

Microbial
- Bioleaching

Combustion Modification

Combustor/Burner Types
- Slagging Combustors
- Rotary Cascading Bed Combustors
- Entrained Combustors
- Limestone Injection Multistage Burners
- Gas Reburning

Fuel Types
- Coal-Water Slurries
- Coal-Gas Co-Firing
- Coal-Water-Gas Co-Firing

Post-Combustion

In-Duct Injection
- Sorbent Injection
- Catalytic Reduction

Post-Combustion Devices
- Vanadium Pentoxide Afterburners
- Ternary Boiler w/Pollutant Capture
- Furnace Injection w/Water Activation Reactor
- Post-Combustion Oxidation w/Fluid Bed Lime Reactor
- Fluid Bed Absorption

Advanced Scrubbers/FGD Devices
- Spray Dryers
- Regenerable Scrubbers
- Dual Alkali Scrubbers
- Electron Beam Scrubbers
- Ion Exchange Membrane FGD
- Magnesium Enhancements
- NOx Specific Scrubbers
- Electrode Precharger Enhancements to Precipitators
- High-Temperature Baghouses

Attachment 4

The Role of Non-Coal Fuels in Meeting Projected Electric Demand:

The use of imported energy, which supplied 21.3 percent of U.S. energy use in 1988, is expected to grow at a very rapid annual rate of 4.0 percent between 1988 and the end of this century. Imported energy will provide almost 30 percent of the total energy used in the United States in 2000.

The Department of Energy's 1989 Annual Energy Outlook, reports that U.S. oil imports are already 50% greater than they were just three years ago. Further, net petroleum imports are expected to increase, from an average 6.3 million barrels per day to 10.2 million barrels per day by 2000. This would account for 55 percent of all petroleum used in the U.S. in 2000 and 24.3 percent of total energy used in that year. (Source: 1989 Annual Energy Outlook, Long Term Projections, Energy Information Administration, Department of Energy, January, 1989.) At these rates of consumption, by 1995 the United States might be spending $80 billion a year on imported oil. This is $52 billion above the $28 billion we spent on imported oil in 1986. That out-flow of U.S. dollars is a principal reason for an unfavorable balance of trade. The Department of Energy's (DOE) 1987 report to the President on Energy Security also reported that by 1995, Middle East producers and OPEC will control as much as 60 percent of the world market for oil.

According to the U.S. Geological Survey, the U.S. has only a 14 year supply of undiscovered natural gas reserves. This would not be so troubling were it not for the fact that the U.S. electric utility industry is sharply increasing its gas usage at a time when our domestic supplies are being depleted. According to the 1989 DOE Annual Energy Outlook, the electric utility use of gas will increase almost 40% by 1995, representing the fastest growing U.S. market for natural gas. This growth in consumption, coupled with the growth in natural gas usage by other sectors, will outstrip domestic production of natural gas resulting in a net increase in imports, with the resulting exacerbation to our current balance of trade problem.

Renewable energy is being developed in the U.S., but it is expected to provide only 13% of the total domestic energy production by the year 2000. As an example of the magnitude of renewable energy available today, according to EEI, all forms of renewable energy provided four-tenths of one percent of the total generation in the U.S. during the twelve month period ending in September, 1989.

Nuclear is another important part of the U.S. electric generation fuel base, and in 1988 represented 20% of the total electricity generated. However, due to environmental, regulatory and economic concerns, no new nuclear generation is currently contemplated. While nuclear and coal accounted for 76% of the country's 1988 generation, they will account for less than 70% by the year 2000 according to the EIA Annual Electric Power Outlook for 1989.

The base of U.S. electric generation should represent a broad range of fuels, and industry should strive to make the most efficient use of fuel. It is clear, however, that U.S. energy policy is best served by a continued reliance on coal as the bedrock of electricity generation; such a policy would help to assure energy security and would help to protect U.S. jobs and industrial competitiveness. In constant dollars, the price of coal has declined over 35% percent since 1978 as a result of technological improvements in the extraction of coal. This trend of coal prices is anticipated to continue for the foreseeable future as contrasted with projected prices for other fossil fuels, which are projected to escalate rapidly through the end of the century.

Attachment 5

Environmental Performance of Innovative Clean Coal Technologies in Comparison to Conventional Coal-Fired Power Plant

Technology	% SO_2 Reduction	NOx Emitted	Waste Characteristics
CONVENTIONAL			
Coal Cleaning	10-30	No change	Solids disposal
Flue Gas Scrubber	90+	No change	Sludge
RETROFIT			
Advanced Flue Gas Cleanup	90+	High reduction	None, Byproduct produced
Limestone Injection Multistage Burner	50-60	Moderate reduction	Dry nontoxic powder suitable for landfill
Slagging Combustor	50-90	Moderate reduction	Dry non-toxic powder suitable for landfill
Gas Reburning	10-20	Moderate reduction	None produced
In-duct Sorbent Injection	50-70	No change	Dry powder suitable for landfill
Advanced Coal Cleaning	30-90	No change	Solids disposal
Coal Slurry	10-90	No change	Solids disposal
REPOWERING			
Integrated Gasification Combined Cycle	95-99	Moderate reduction	Usable slag, saleable sulfur and small quantities of other solid wastes
Pressurized Fluidized Bed Combustion	90-95	Moderate reduction	Dry granular nontoxic solid waste
Atmospheric Fluidized Bed Combustion	85-90	Moderate reduction	Dry granular nontoxic solid waste

Source: Department of Energy's report,
"America's Clean Coal Commitment,"
February 1987

Attachment 6

ESTIMATED COMMERCIAL AVAILABILITY OF CLEAN COAL TECHNOLOGIES

Government policy-makers are concerned about *assuring the commercialization of clean coal technologies* and *not losing or wasting the multi-billion dollar investment now being made in the development of these technologies.* These concerns are raised in the context of the debate about the need to impose more stringent controls on emissions. The often asked question is: "How much time is required to commercialize clean coal technologies?" The answer is twofold:

First, sufficient time to demonstrate, deploy and integrate these technologies into the electric generation system. More specifically:

- a successful demonstration/deployment program could result in *a variety of clean coal technologies available for commercial order by the mid- to late-1990's.* An emissions control program that mandates reductions in the early 1990's would prevent utilities from directing resources to clean coal, resulting in a postponement or abandonment of new technology development; and
- once clean coal technologies are available for commercial order, *an additional period of time — as much as 5 to 10 years — will be required for utilities to develop confidence in the technologies and place them into widespread commercial use.** A control program that mandates significant reductions during this same time period and that does not provide flexibility for compliance, will force utilities to abandon these technologies in favor of currently available (and proven) control mechanisms.

Second, assuming a sufficient amount of time is provided before any mandated emission reductions are required, clean coal technologies will require full funding of the on-going $2.5 billion clean coal program; inclusion of support for multiple applications of the same or similar technology (i.e. deployment) as a part of the on-going program and modification of existing regulations governing electric rates and flexibility in environmental regulations currently applicable to new technology development.

* *User confidence* can only be established by the installation or utilization of the commercially available technology on a succession of existing or planned units. Utilities not directly involved in the initial technology demonstration will subsequently undertake installation or use of the technology in much the same unit by unit fashion. *The process of initially incorporating these technologies into the systems of various utilities will take time -- time to evaluate the technology's performance and to decide to use it on additional units; time to site such projects; to complete permitting and regulatory approvals, including approvals by utility rate regulatory agencies, and to place orders and receive equipment from manufacturers of the clean coal technology.* As user confidence increases, a greater number of each successfully demonstrated technology will be incorporated into various utility systems until the technology penetrates the available market and is generally accepted industry-wide as a readily available and proven option.

Attachment 7

THE THREAT OF U.S. EPA'S WISCONSIN ELECTRIC POWER DECISION

The Threat.--A recent administrative decision by U.S. EPA involving Wisconsin Electric Power could have a far-reaching, potentially disastrous effect on American business.

- Entirely responsible, previously uncontroversial business decisions to refurbish existing plant and equipment could trigger unprecedented legal obligations to invest in unjustifiably expensive air pollution controls, even when there is no air quality problem.

- EPA's decision, which covers the whole of American industry, would require older facilities to retrofit technology that is designed primarily, if not exclusively, for application at brand-new plants.

Background.--Since passage of the 1970 Clean Air Act, there has developed a clear, universally recognized distinction between EPA's regulation of existing industrial plants versus new facilities. Existing sources have been required to meet emission limitations that assure attainment and maintenance of EPA's national ambient air quality standards, particularly those for sulfur dioxide and particulate matter. As such, emission limits for existing sources have come to be known as "air quality driven." New plants, on the other hand, have been subject to EPA's new source performance standards (NSPS) which require that newly constructed plants employ the "best technological system of continuous emission reduction." Emission limitations for new sources are therefore termed "technology-driven." This technology mandate was reinforced by the 1977 amendments to the Clean Air Act which established, on a statutory basis, the prevention of significant deterioration (PSD) program. Under PSD, new sources are also required to incorporate "best available control technology."

Until recently, American industry could be certain that existing plants would not be required to install technological pollutant control systems under either the NSPS or PSD programs except in very isolated instances. These instances included source "modification" or source "reconstruction." (PSD regulations speak in terms of "major modification," whose definition is closely akin to "modification" for NSPS purposes.) "Modification" occurs when there is any physical change in, or change in the operation of a source which increases the amount of pollutant emissions. "Modification" has not historically applied in the absence of an increase in the size of an existing plant or a major change in operations, e.g., increase in generating capacity of a boiler. "Reconstruction" takes place when existing plant refurbishment exceeds a 50% replacement cost criterion, even when plant size does not change, i.e., EPA does not allow an existing source to be rebuilt from the ground up unhindered by standards applicable to entirely new sources.

WEPCo Decision.--This basic distinction is now brought into question by an EPA decision in late 1988. The Wisconsin Electric Power (WEPCo) case arose when the utility undertook major repair work at its Port Washington generating station. EPA reviewed this repair work to determine whether modification, major modification or reconstruction took place. Although the WEPCo repairs fell short of the cost criterion for reconstruction, involved only like-kind replacement of plant components and did not entail a capacity increase, EPA ruled in October 1988 that the WEPCo repairs at Port Washington triggered the technological control mandate under EPA's NSPS and PSD programs.

The Consequences.--EPA's decision has caused the long-lived distinction between existing source and new source regulation to be blurred, if not eradicated. Even though the WEPCo repairs have done nothing more than restore the generating capability of Port Washington to its original design level, EPA applied an extremely harsh, irrational test to determine that an emissions increase would occur. For NSPS, EPA weighed emissions based on operations with deteriorated equipment, against emissions based on operations with repaired equipment, even though the utility never intended regular operations with the plant in a deteriorated condition. For PSD, EPA compared actual emissions at Port Washington prior to the repairs to entirely theoretical maximum potential emissions after repairs. Because potential emissions assume source operation at maximum capacity for every hour over the course of a year, this comparison is structured to yield only one conclusion, an emissions increase. EPA's "apples to oranges" analysis subjects WEPCo -- or any other similarly situated source -- to the technology requirements of NSPS and PSD.

- This EPA decision does not, by its terms, apply merely to utility life extensions; on the contrary, it is couched in general terms and logically applies to any industry -- especially those in America's heartland -- which must repair existing manufacturing facilities and whose potential emissions will exceed actual emissions under EPA's irrational comparison test.

- This EPA decision represents a major intrusion upon the long-recognized authority of state governments to administer the Clean Air Act and state clean air laws; by broadening the class of sources subject to the federal NSPS and PSD programs, EPA effectively "federalizes" emission limitations in state implementation plans which govern existing source operations.

- This EPA decision stands as a deterrent to the evolution of a new generation of pollutant control systems set in motion by the Department of Energy's Clean Coal Technology (CCT) program. Based on EPA's calculus, removal of experimental and developmental control technology from a CCT host plant could well constitute a "physical change" giving rise to an emissions increase, subjecting the source to NSPS and PSD.

- This EPA decision furthers its cost-ineffective "command and control" philosophy and approach to emission controls embodied in NSPS and PSD. It forces industry to adopt particular, usually exorbitantly expensive technological controls to a widening category of plants with little regard for the Clean Air Act's fundamental goal of air quality improvement.

Conclusion.--The WEPCo decision means that capital investment undertaken to maintain or enhance efficiency and productivity could boomerang. Instead of saving money, industry can well find itself stuck with the massive capital and operating costs of new air pollution equipment, even when air quality is not threatened by the status quo. More likely, the WEPCo decision will deter corporate managers from undertaking cost-effective plant refurbishments as the need arises.

3/3/89

The **Chairman**. Thank you.

Next, Chris Farrand, who is Vice President of Peabody Holding Co., who has testified a number of times before and very constructively before this committee.

Welcome, Chris.

STATEMENT OF CHRIS FARRAND, VICE PRESIDENT, GOVERNMENT RELATIONS, PEABODY HOLDING CO., INC.

Mr. **Farrand**. Thank you, Mr. Chairman. I will confine my oral remarks to the specific questions that the committee addressed to us.

First of all, I want to say that I represent Peabody and not the National Coal Association today. Peabody is the Nation's largest producer of coal. We have traditionally been a high sulfur coal producer, but in fact we are now also the largest low sulfur producer in the United States. So I come to you with two hats on the equation of coal switching in this issue.

Let me address first the issue of the regional impacts. Peabody has developed a model based on power plant and fuel use data acquired through DOE's Forms 4 and 423, and we have used the actual empirical data to determine what we think the optimizing compliance strategy of each utility system would be in meeting the requirements of both Phase I and Phase II of Title IV of S. 1630.

I want to make a cautionary note about these models, however. We have found that they are best suited for comparing legislative proposals and that they are much less reliable when trying to quantify the actual impacts of a single proposal. The reason this is the case is that they are very sensitive to the assumptions used. So when you are comparing proposals, you can use the same assumptions throughout and get some idea of the relative impact of different bills.

In this case where we have been asked to identify the regional impacts of this particular proposal, it is probably less reliable. We have utilized assumptions that are what we think are real market assumptions, our best judgment of what will happen to both coal prices and scrubber costs that will dictate the amount of fuel switching or technology retrofits that will occur in meeting the requirements.

With that cautionary note, let me just give you a few numbers about the regional impacts. We estimate that there will be somewhere on the order of 25 million tons of coal switched in Phase I of this bill. We would probably call the range something between 20 and 35 million tons.

I might add parenthetically that this is a smaller number, believe it or not, than the administration estimates, and that may be a factor of our assumptions used versus theirs.

That amount of coal switching we estimate, based on current productivity rates in the states where those coal production losses are likely to occur, will create a job impactor, a job dislocation of about 5,000 direct mining jobs and about 20,000 total jobs dislocated as a result.

In Phase II we arrive at a number of coal tons switched of about 60 million tons, and the range there is about 50 to 100 million tons, a sizable jump obviously. The job impact based on that number would be about 11,000 coal jobs and about 45,000 total jobs.

The states most heavily impacted by the displacement of coal production would be Ohio, Illinois, Indiana, Kentucky, Pennsylvania and West Virginia.

I have in my written——

The CHAIRMAN. You do not accept that tradeoff of high sulfur coal jobs and low sulfur coal jobs?

Mr. FARRAND. No, I do not, Mr. Chairman. We operate in states like West Virginia and Wyoming, and I can tell you from our own experience that the average productivity in Wyoming is on the order of eight times as great as it is in the eastern underground mines. So to the extent that the displacing or the replacement coal comes from states like Wyoming with large open pit surface mines, the job impact is not a direct tradeoff.

The CHAIRMAN. In the east, are they going to use the low sulfur coal in West Virginia and Appalachia because of the transportation costs?

Mr. FARRAND. They will, and we believe that the intrusion of western-produced coal will be limited by transpiration and by the capacity of certain boilers in the midwest to utilize the lower Btu western coal; and there are other bottlenecks.

There is also a constraint we see in this bill, however, to the utilization of eastern low sulfur coal based on the imposition of the cap and the offset requirement. If I can digress for a moment, I would like to explain that.

The second phase requirement for a powerplant is 1.2 pounds, but it is 1.2 pounds as an admission rate times an historic Btu input factor based upon the average of 1985 to 1987 fuel use or fuel consumption. If you assume any kind of moderate growth in demand for electricity from plants utilizing eastern low sulfur coal, we think that the effective emission rate limit in a lot of those plants is not going to be 1.2 but it is going to be something on the order of 1 pound or even less.

What that will do to eastern low sulfur coal is probably eliminate it as a discreet compliance option for the simple reason that there is very little 1-pound coal available east of the Mississippi. In 1988 I think there were 16 million tons out of something like 575 million tons produced east of the Mississippi that would have met the one-pound limit. If the effective rate goes to .9, the amount of available tonnage that is here that would have met that limit is about 4 million out of 575 or 576 million tons.

Now that is not to say that there is not more of that clean coal available in the east, but we believe that the supply of what would become the effective compliance coal is quite limited, so that will affect not so much the intrusion of western coal into eastern markets but the degree to which eastern utility power plants have to be scrubbed or partially scrubbed in order to meet that effective limit——

Senator MCCONNELL. Let me just interject for a minute and ask you the same question I asked Mr. Yamagata. Is it your view that this is in effect a mandated scrubber bill?

Mr. FARRAND. For much of the country, the effect of the cap and the offset will eventually require pretty broadbased universal scrubbing to some degree. Now maybe you are going to use a moderately low sulfur coal with partial scrubbing or dry scrubbing or some other less than full reduction retrofit technology. The fact is eventually not just to meet the requirements of the year 2000 but to meet the requirements on those facilities as more offset are required for new plants coming on line, the answer is yes, you will have to——

Senator McCONNELL. That solution will be so extensive, in your view, that we may not buy enough time for clean coal technology to come on line?

Mr. FARRAND. Well, I endorse Ben Yamagata's comments about that. I do think that we have a problem both in Phase I in providing enough time for the broad scale application of retrofit technologies and in Phase II even with the deadline extension provided in the bill in providing enough time for the broadscale application of repowering technologies. I do think that is a problem.

Let me move on, if I may, Mr. Chairman, and I will skip the clean coal technology part. I think Ben has said it all very well, except to say that we at Peabody thoroughly endorse the concept, and we have invested a considerable amount of money even apart and before there was a clean coal technology program in trying to advance those technologies to the marketplace.

I was asked to comment on the clean state provision, and in spite of the fact that I believe four of the seven states are represented on this committee I would have to say that in its present form I cannot endorse this concept. I have some doubts whether it will survive the legislative process, but let's just get into that for a minute.

The criteria used to determine the clean state are two. Obviously, 50 percent of the generation has to emanate from plants that are scrubbed, and you only count toward the 150,000 ton ceiling those emissions from utility power plants. You do not count industrial emissions.

I would argue that in terms of their environmental impact it matters not a whit whether they emanate from a utility plant or some other kind of source. So that criteria seems to be a bit arbitrary.

Senator CONRAD. Is that not the criteria in the overall bill? I mean, that is not specific to the clean state provision. That is the way this whole bill is written.

Mr. FARRAND. Senator, I understand your point, but the overall bill seeks an approximate 50 percent reduction in overall requirements nationwide. It happens to target utility power plants, but the fact is it is looking at reducing the effective overall sulfur emissions. So I am not certain any one state should escape the onus of having to deal with its nonutility emissions in terms of qualifying as a clean state.

The other problem, which perhaps is one of its most serious faults, is that it is a snapshot approach. It takes one year and says if you have met the requirements in that year you are henceforth a clean state. It does not accommodate states that may have met the same standard in years subsequent to that or that may in the future meet those standards. To that extent, I think that probably they are secondguessing.

The third problem as I see it is that the 50 percent scrubbing requirement seems to give more credence to the application of technology than it does to the attainment of low levels of emissions, and I think that is a somewhat artificial standard.

Having said that, however, there may be a rationale for a clean state provision if, indeed, it can be made to be an incentive. I do not know. I am not prepared today to discuss with you precisely what the criteria ought to be, but certainly if you are going to have such a provision it ought to be an incentive for states to attain the goals in a more innovative fashion perhaps than is prescribed to those states not now included in that category. So I do not discount the idea totally, but I discount the form in which it has been expressed in this bill.

Let me get on to the subject of industrial emissions. I find myself in some agreement with the administration on this point. If we assume that the opt-in provisions in the bill and trading itself will function properly, that being a very large assumption, then we believe that where they are cost effective, indeed, industrial emissions will be controlled as a result of this bill; that utilities will find a way to purchase offsets, if you will, from nonutilities where it is more cost effective to obtain those reductions and by either allowances for themselves or for some other benefit.

So I am not certain I am prepared to endorse the specific targeting of industrial facilities or any size industrial facilities in this bill at this point.

Historically, in previous iterations of acid rain legislation that almost universally targeted utility plants, the issue of whether industrials ought to be specifically targeted has only arisen in this bill or in the administration bill primarily because this bill is more extensive than any we have seen so far. The offset and the cap provisions require a great deal more activity in cost control and, therefore, point out the apparent disparity between the treatment of utility and nonutility sources.

I would like to conclude by getting to one question that I was not specifically asked but which was raised this morning by Senator Bumpers, as a matter of fact, and it has to do with the so-called Class of 1985.

Senator, these facilities you talk about are largely supplied by Peabody Coal. The Class of 1985 provision in the Senate committee bill is really very restrictive, and I think that it is in need of amendment.

If you have a facility, as is the case in your plant, where the producer of coal happened to ship the cleanest coal on record that particular year and it is going to be very hard, if ever, to match that quality of coal in successive years—and bear in mind that this is coal that is dedicated to those specific power plants—in order to meet the requirements of that provision you are probably going to have to apply technology, and I would say apply technology to probably the cleanest coal produced in America or anywhere in the world.

We ship coal to Arkansas that meets a .4 pound standard raw. That compares very favorably with obviously any other coal produced in the United States. On the other hand, you may have a circumstance in which people have a facility already scrubbed that is using moderate sulfur coal but it happened to have a fairly low capacity factor in the base years.

The net result is unless the allowances for excess controls are made readily available elsewhere in the country, these clean plants who have paid for their emission reductions already may end up with excess clean coal emitting capacity that they cannot utilize.

We have made specific suggestions to the EPW Committee on alternative options that might be afforded to these very clean plants without impacting seriously the overall emission reduction requirements. They have come to no conclusion on language on that, but we do see it as a very serious and very unfair problem.

That concludes my oral comments. I would be happy to respond to any comments.

[The prepared statement of Mr. Farrand follows:]

Testimony by

Chris Farrand
Vice President, Government Relations
Peabody Holding Company, Inc.

Before the

Committee on Energy and Natural Resources
U. S. House of Representatives

on

Energy Policy Implications of S. 1630

Washington, D. C.

January 24, 1990

My name is Chris Farrand. I am Vice President of Peabody Holding Company, Inc., which through its subsidiaries, including Peabody Coal Company, is the nation's largest coal producer. In 1989, Peabody produced nearly 87 million tons of steam and metallurgical coal. We currently operate 42 mines in 10 states. Traditionally a producer of high-sulfur coal, Peabody is now also the nation's largest producer of low-sulfur coal.

I was asked to testify today on the acid rain provisions of S. 1630, the Clean Air Act Amendments reported on December 20, 1989, by the Senate Committee on Environment and Public Works. I was requested to address the regional impacts of the acid rain control measures of Title IV and, specifically, the implications of the so-called clean state credit provision, and the possible inclusion of industrial sources of sulfur dioxide emissions among those to be controlled. Our testimony will deal primarily with the regional impacts on coal markets, although we will include some comments about the basic structure of the program.

Peabody has developed its own analytical model for comparing acid rain proposals. The model utilizes actual powerplant and fuel use data derived from the Department of Energy's Form 4 and Form 423. Using this data, we are able to determine the average annual emission rate for each powerplant, each utility system and each state. From this emission rate data, we are then able to find the most economic approach by which each utility can meet its emission rate limitations by either switching fuels or flue gas desulfurization. Obviously, S. 1630, and the predecessor legislation proposed by the Administration, imposes tonnage limitations rather than emission rate requirements, but the Peabody model is designed to account for this fundamental difference and translate emission rates into tonnage emissions at each facility.

I have appended to this testimony a description of the analytical model and the assumptions Peabody used to determine the quantitative impacts of Title IV of S. 1630. These assumptions represent Peabody's best estimate of conditions affecting our industry. I would like to caution the Committee about the use of analytical models to determine the impact of acid rain controls. These models are extremely sensitive to the assumptions used. A change in the assumption about the cost of flue gas desulfurization (scrubbers) or the expected delivered cost of certain types of coal can alter the results substantially.

By and large, Peabody has utilized this analytical model to compare the impacts of different acid rain control programs. We believe such models are useful and reasonably reliable when used for comparative purposes, but they are less reliable when used to determine the quantitative impacts of a single proposal. With that cautionary note, we offer our analysis.

Before venturing the results of our analysis, I would like to make a few comments about the basic structure of S. 1630 and its predecessor, the Bush Administration proposal of last July. While all previous acid rain control proposals have set arbitrary emission control levels and deadlines, these two proposals have added very significant elements which are not only arbitrary, but appear as somewhat punitive. The 10-million-ton reduction in annual SO_2 emissions is now reinforced by a federally-administered allowance program which seriously inhibits operating flexibility within a utility system. Compounding the problem is the addition of a "cap" or ceiling on gross emission levels by the year 2000, with an offset requirement for emissions from new plants constructed after that date.

With all their specificity, these very arbitrary and firm limitations do not appear to be designed to achieve specific reductions in acid deposition levels, so we do not know whether there will be any difference in the effects on the environment between a bill which uses a more flexible and less expensive emission rate control strategy and the specific tonnage cap imposed by S. 1630.

In other words, the reduction targets and specifically the permanent cap on emissions may have a political origin, but there does not appear to be scientific basis for these very precise and very restrictive requirements. One would hope that the cost of the incremental reductions to be achieved through this bill would have some corresponding incremental environmental benefit. None is in evidence.

EPA's own analysis of the relative cost of achieving different SO_2 reduction targets shows significant increases in incremental costs as the target reduction levels increase. For example, EPA estimates that an 8-million-ton reduction would cost $2.2 billion annually, while a 10- million-ton program will cost $3.8 billion per year. By contrast, a 12-million-ton program would cost $8 billion annually. The average cost per ton removed for the 8-million-ton option and the 12-million-ton option are $275 and $670, respectively, a sizable increase. But when the cost-per-ton is measured on an incremental basis, the cost of removing the additional tons beyond the 10-million level amounts to $2,100 per ton. The very steep incremental cost curve means that, over time, the cost of complying with the tonnage cap and the offset provision could become very great indeed, because they can only be met by achieving incremental reductions at existing powerplants beyond those necessary to meet the 10-million-ton reduction target.

Regional Impacts of S. 1630

Peabody's analysis of the provisions of S. 1630 shows significant but not overwhelming shifts in coal production resulting from the Phase I and Phase II sulfur dioxide control requirements.

In Phase I, or by 1995, we anticipate a shift of approximately 25 million tons of annual coal production or about 2.5 percent of current levels of U. S. coal production. At current levels of productivity, this would result in the dislocation of approximately 5,200 direct mining jobs. The indirect job impact could affect 15,000 individuals.

In Phase II, effective in the year 2000, the shift in coal production would approach 60 million annual tons, or about 5 percent of expected U. S. production at that time. Such a shift in coal production could result in the dislocation of approximately 11,000 direct mining jobs and, with indirect job dislocations, affect about 44,000 individuals.

The model indicates that coal production losses are likely to occur in the states of Ohio (12 MMT), Illinois (9.5 MMT), Indiana (4.2 MMT), Pennsylvania (7.6 MMT), West Virginia (8.1 MMT), and Kentucky (6.1 MMT), with smaller losses in Oklahoma, Missouri and North Dakota. The model does not try to determine the amount of replacement coal which might emanate from each state, but the primary sources would be southern West Virginia, Virginia, to a lesser degree east Kentucky, and the coal producing states of the West.

There are several factors that could alter these coal market shifts. The tonnage cap provisions of S. 1630 will lower the effective emission rate limitation for powerplants in both Phases. Depending upon the growth in electricity demand between the 1985-1987 baseline years and the deadlines of 1995 and 2000, the effective emission rate limits are not likely to be 2.5 lbs.

and 1.2 lbs. per million Btu's, respectively, as prescribed in the legislation. In order to accommodate expected increases in demand and in plant capacity factors, effective emission rates may be in the order of 2.25 lbs. per million Btu's in 1995 and 1.0 lbs. or even 0.9 lbs. by the year 2000.

There is very little coal produced in the eastern U. S. which can achieve these lower emission rates in Phase II without technology retrofits. In 1988, only 16 million tons of coal produced east of the Mississippi would have met an emission rate of 1.0 lbs. per million Btu limitation, and less than 4 million tons would have met a 0.9 lbs. standard. Moreover, much of this lower sulfur eastern coal is now dedicated to the steel industry. On the other hand, almost half of the coal produced in the west in 1988 would have met a 1.0 lbs. standard. However, we believe transportation costs and plant operational constraints will preclude significant penetration of this western low-sulfur coal into markets now enjoyed by coal producers in the Midwest or Appalachian regions.

To the extent that eastern low-sulfur coal is not available to meet the lower effective emission rates that might be required to meet the Phase II emission cap, there would be less fuel switching and more scrubbing in the region than the model indicates. Job dislocations would decline correspondingly.

There are numerous other factors which could alter the degree of fuel switching among regions projected by our model. Among these are changes in scrubber costs, the emergence of new clean coal technologies, particularly, retrofit technologies, physical limitations on retrofits at certain powerplants, and potential bottlenecks in transportation.

Putting aside the very real human impacts of any degree of coal production shifts, from the standpoint of the coal producing industry, we believe the industry can accommodate the degree of fuel switching envisioned under this legislation. Many companies, Peabody included, have already begun the process of changing our product mix to meet the new market realities. In the past 12 years, the average sulfur content of coal shipped by the entire U. S. coal industry has declined by 37 percent, albeit at a sacrifice to the economies of some traditional coal producing regions of the country.

Clean Coal Technologies

I will defer to my colleague Ben Yamagata for substantive comments on the clean coal technology provisions of S. 1630. I would only add that Peabody believes very strongly in the need to develop and commercialize these new technologies. Even apart from the formal Clean Coal Technology Program, Peabody has invested in specific clean coal projects in order to advance these new technologies.

The principal concerns we have about the clean coal technology provisions of S. 1630 are: (1) the need to expand the list of technologies and potential technologies eligible for the incentives, (2) the need to restore the FERC-related incentives which were in the Administration's bill but excised in the Committee's version, and (3) the effect of the deadline on the application of repowering technologies on existing powerplants.

"Class of '85" Powerplants

Under the Bush Administration bill, plants with 1985 SO_2 emission rates averaging less than 1.2 pounds per million Btus -- the so-called "clean plants" -- would have to maintain their actual 1985 emission rates, but they would not be constrained in terms of capacity utilization. In other words, a unit with a a very low emission rate which was under-utilized during 1985 could increase its fuel consumption and be utilized at its planned capacity levels, so long as it did exceed its historic emission rate. S. 1630 changed this provision to limit emissions from these clean plants, under any circumstances, to 120 percent of the actual tons of emissions produced during 1985. In effect, this change substituted a tonnage cap for a rate cap for this class of clean plants.

The impact of this change could be significant. If, for example, one of these clean plants had been under-utilized (i.e., had a low capacity factor) during the baseline period, there may be no opportunity to fully utilize the facility, unless the operator were able to purchase excess allowances from another facility. If the plant had been retrofitted with a scrubber, the operator would have to pay a double penalty; in addition to the price of a scrubber, the operator would also be forced to purchase more expensive low-sulfur coal. If the plant were not fitted with a scrubber, but relied upon very low-sulfur coal to achieve its status as a clean plant, there may be no coal available with an emission rate low enough to accommodate full utilization of the facility.

While the Environment Committee staff appears to recognize the problem created by the proposed tonnage cap on clean plants, they have not been able to find language which addresses the problem for all the plants in this category. This provision seems particularly punitive to the operators of the facilities which are among the cleanest in the country in terms of sulfur emissions.

We would recommend that the bill be amended to provide operators of these clean plants the option of using the control method outlined in S. 1630 (120 percent of baseline average emissions) or using a presumed 65 percent capacity factor against which the baseline emission rate is applied. A third important option would allow operators to measure their baseline capacity factor against a 1.0 lbs per million Btu limit or the State Implementation Plan (SIP) limit, whichever is lower. Utilities would be obligated to select one of these emission limitation options for each clean plant in the system.

Clean States Credit

The Committee bill contains language which exempts states from both the Phase I and Phase II emission reduction requirements _if_ they produced less than 150,000 tons of sulfur dioxide emissions from utility powerplants during 1985 _and_ if at least 50 percent of electricity produced in the state during 1988 was generated at units fitted with scrubbers. After the year 2000, the provision also limits emissions at each unit in the state to the average annual amount which _will be_ emitted during calendar years 1996-1998. We understand that six (6) states enjoy this exemption.

We have several comments about this provision. First, the criteria measures only utility emissions; there may be some states which emit large amounts of sulfur dioxide from non-utility sources, but which nevertheless would qualify as a clean state. In terms of its impact on the environment, it matters not a whit whether the molecule of sulfur dioxide in the atmosphere is emitted from a powerplant or a source other than a powerplant.

Second, the provision contains a cap on emissions based not on historical (1985-1987) emission levels, as is the case with units in all other states, but rather on _future_ emission levels measured in 1996-1998. A so-called clean state would have an opportunity to adjust its future emissions to establish a baseline against which the cap is applied. Hence a state with powerplant units having excess capacity could substantially increase its electricity generation -- and its sulfur emissions, even beyond the 150,000 annual-ton limit -- and still remain classified as a clean state.

The criteria which demands that a clean state must have scrubbed at least half of its generating capacity seems designed to reward states for technology utilization more than for cleanliness. If a state has achieved a low level of emissions, it should be rewarded for that achievement, regardless of how it was attained.

Perhaps the most troubling feature of the clean state credit provision is that it does not provide an incentive for future achievement on the part of the states. Qualification is based on a snapshot approach that looks at emission levels in one year in the past. No opportunity is provided to other states which may have attained similar levels of emissions subsequent to 1985 or to states which might achieve even lower levels in the future in order to try to avoid the specific requirements for sulfur reductions in Phase I and Phase II.

There is a rationale for a clean state provision, properly designed, which would exempt states from the requirements of Sections 404 and 405 if they had attained or were able to attain in the future total emission levels below a prescribed threshold, regardless of the sources involved. Such a provision could become an incentive for states to create emission reduction strategies more innovative and flexible than those required in the Committee bill.

Inclusion of Industrial Sources

Peabody was asked to comment on relative burden for sulfur dioxide imposed on industrial sources compared to the onus placed on utility sources. Estimates of sulfur dioxide emissions from non-utility sources are imprecise, but it is believed that annual emissions from such sources range from 7 million to 10 million tons. Much of these non-utility emissions are derived from sources other than coal.

The Administration's acid rain control proposal exempted industrial sources from sulfur dioxide requirements, while S. 1630 would place a ceiling on such emissions at a level 1.5 million annual tons below 1980 emission levels from industrial sources. We believe that this "cap" on industrial emissions would actually permit an increase over current annual emission levels, since there has been a substantial decline, perhaps as much a 2.7 million annual tons, in industrial sulfur dioxide emissions since 1980.

In previous Congresses, nearly all the acid rain control proposals were exclusively targeted at utility emissions, on the theory that the most cost-effective control strategies would center upon these generally larger sources. Given the more extensive utility reductions required to meet not only the 10-million-ton reduction target, but the emission cap and offset requirements in the Administration's proposal and S. 1630, there appears to be more concern now about the disparity in the treatment on utility and non-utility sources.

So long as emission trading continues to be permitted between utility and non-utility sources and so long as co-generation facilities are included in the category of plants subject to controls, Peabody believes that industrial sources need not be targeted for specific reductions. Where it is cost-effective, utilities should be able to substitute reductions at industrial facilities to offset emissions from powerplants.

We would add a cautionary note, however. Whenever an arbitrary threshold is established, whether it is the exclusion of industrial facilities or the exclusion of powerplant units of less than 75 megawatts in size from regulatory requirements, there is a tendency for such facilities to become the market option. If the cost of electricity sold to industrial facilities becomes too great as a result of added emission control requirements, industrial concerns may develop their own generating capacity. Such units would now be governed by the New Source Performance Standard, so the threat of significant emission increases from such sources is not great.

Smaller utility powerplants of less than 75 megawatts may be moved up the dispatch cycle as a result of their exemption from specific controls. To the extent that these smaller units significantly increased their contribution to overall utility SO_2 emissions, there would be a rationale for their inclusion in the control program. However, from a coal production standpoint, it would be disadvantageous to include these smaller facilities. With controls applied, these smaller units may find sources of fuel other than coal to meet the standards. We would expect a loss of market share in this category of smaller utility units.

Permit Fees

I would like to register a concern with this Committee about the very burdensome permit fee structure in S. 1630. The bill would assess a permit fee of "no less than" $25 per ton of regulated pollutant. At current emission levels, the fees for permits governing sulfur dioxide emissions on utility powerplants alone will approach $400 million per year. Fees related to utility emissions of other pollutants, primarily nitrogen oxides, will add another $200 million to the annual permit fee structure for utilities. We realize that the emission allowance system established under the Administration's bill and S. 1630 is complicated, but it is hard to imagine that the cost of administering the program for utilities would require annual proceeds of $600 million or more. Moreover, this figure does not include the potential fees which might result from the regulation of particulate emissions and hazardous air pollutants which will be discussed by a later panel of witnesses.

We have seen estimates of the combined annual proceeds of the permit system governing all regulated air pollutants in S. 1630. These estimates range from $2 to $3 billion per year. It is my understanding that these permit fees were not included in the analyses of compliance costs.

Summary

Peabody believes there will be moderate shifts in coal production as a result of the acid rain provisions of S. 1630, but the producing industry has the inherent capability of meeting these changing market circumstances. However, there will be economic dislocations in some high sulfur coal producing regions.

We would recommend changes in the clean state credit provision to provide incentives for state initiatives to control acid rain precursor emissions.

The limitation on emissions from clean ("Class of '85") plants should be amended to avoid artificial limitations on the use of generating capacity from the clean plants.

Finally, we believe that the emission trading provisions, rather than specific reduction targets, should determine the extent to which industrial sources should be impacted by the emission reduction requirements.

This concludes our formal statement. We would be pleased to respond to any questions the Committee may have. Peabody appreciates the opportunity to appear before this Committee.

Attachment

ACID RAIN MODEL BASIS AND DATA

The Peabody acid rain model is based on electric utility fuel consumption and SO_2 emissions only. The quantity, and quality of the fuel is based upon 1988 purchases as reported on FERC Form 423 reports. The cost of fuel is based upon 1988 from the same source. SO_2 emissions were derived from consumption data gathered on EIA Form 759 for 1988.

Calculation of Reductions and Enforcement Mechanism

The allocation of reductions in SO_2 emissions to each state is done in direct accordance with the legislation. In most cases this entails the following steps:

1. Total all emissions in each state over a given or "base" emission rate, such as 1.2 pounds of SO_2 per million BTU consumed.

2. Calculate the percentage that each state's total represents of the total of all emissions above the base for the specified area. In some cases this area is the entire 48 contiguous states.

3. Multiply the resulting percentage by the total mandated reduction to arrive at the reduction allocated to each state. In bills where growth effects are required, the projected emissions growth is simply added to the mandated reduction in each state.

The model assumes an enforcement mechanism based on an "Allowable Emission Rate" or AER for each state. Three basic assumptions are used in the calculation of the AER:

1. The capacity factor, heat rate and generation for each existing coal or oil-fired plant remains constant.

2. No existing plant is allowed to raise its emission rate above the 1980 level.

3. In those instances where the legislation requires that SO_2 emissions from new (post 1980) plants be offset, further reductions from existing plants are made to arrive at total allowable emissions as of the effective compliance date.

Once total allowable emissions are determined and allocated to each state, required emission reduction for each utility system is calculated by multiplying the AER times the total amount of BTUs consumed in coal and oil-fired powerplants that were operating above the AER. Some legislation sets an AER for each state and no calculation is necessary.

Inter-System Trading

Once the required reduction is established for each utility system, the model then allows each utility to achieve the reduction on a system basis in the most cost effective manner. As few as one or as many as all plants in a system with emissions over the AER may be required to reduce emissions. That is, intra-utility system trading among sources operating above the AER is permitted, but not inter-system or inter-state trading.

Replacement Fuel Cost and Quality

The cost and quality of replacement fuel that might be selected by a utility to achieve the required reduction is calculated from the same FERC Form 423 used for calculating existing emissions and fuel costs. This "compliance" fuel in each state is generated from shipments entering the state or an adjacent state which were below the AER during 1988. The quality of the compliance fuel is the weighted average of the qualities of all such shipments, while the cost is the weighted average plus an adjustment for the "demand push" that would be encountered in the event that acid rain legislation is enacted.

The amount of the demand push for the compliance fuel is bounded by the implied cost of the other main compliance strategy; namely, installing and operating flue gas desulfurization equipment at each plant and continuing to use high-sulfur coal. For those states where (a) significant SO_2 reductions must be made and (b) coal switching is clearly a viable option, the average differential between the two options is approximately $10.00 per ton delivered. This in turn represents a 30 percent demand push on the 1988 delivered price of low-sulfur coal which should be available to the coal producer and/or the shipper. No attempt has been made to allocate the premium between these two industry segments. For legislation where the reduction occurs in two phases with moderate fuel switching resulting in the first phase the demand push is 15 percent in phase one and 30 percent in phase two.

Scrubbing Costs

Flue gas desulfurization (scrubbing) costs are developed utilizing EPRI* projections for capital and O&M. The costs are adjusted for the number of megawatts of scrubbing capacity to be installed and for the sulfur content per million BTU of the fuel. Scrubber capital costs are increased to account for retrofitting the generating plant. O&M costs reflect the actual number of hours of operation of the plant during 1988, and it is held constant throughout the period of analysis. Scrubbers are assumed to achieve a 90 percent SO_2 removal efficiency for all applications. In those instances where less than 90 percent total SO_2 removal is required to achieve the AER, partial scrubbing is utilized and the costs are scaled accordingly. Capital costs are annualized by applying a capital recovery rate of 17.9 percent. The costs are reported in 1990 dollars.

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*Electric Power Research Institute, Retrofit FGD Cost-Estimating Guidelines, October 1984.

Strategies for Reduction

In this model, there are three alternative methods for achieving reductions. The first is to substitute compliance fuel. The cost in this case is the difference between the current fuel and the compliance fuel plus the demand push as noted above. Second, a plant could retrofit a scrubber. In this instance an annual cost is calculated by adding the carrying cost of the capital needed for the construction to the yearly cost of operation and maintenance. The model limits the application of scrubber retrofits to coal-fired plants larger than 200 megawatts of capacity. Finally, if the legislation calls for the phasing of reductions in at two or more different dates the model will allow for fuel switching in the initial phases followed by scrubbing.

Distribution of Coal Displacement and Employment Impacts

After an economic decision regarding the most cost effective compliance strategy has been made at each plant, the coal that is displaced is summed for each consuming state. This total displacement is then allocated to producing states according to the percentage each producing state contributed to the total of all such shipments in 1988. In other words, if producing state A contributed 50 percent of the coal over the AER in consuming state 1, then state A would receive a 50 percent allocation of the total coal displaced in state 1.

Using data from MSHA, the average mine productivity in each producing state is divided into the tons displaced to estimate the number of miners expected to lose their jobs because of coal displacement. To estimate total job impacts, the model uses a previously developed Department of Commerce multiplier of three support jobs for each direct mining job lost.

Other Assumptions

A number of other assumptions have been made in addition to those noted above.

1. All costs used in the model are 20-year levelized costs using 1990 dollars. The levelizing procedure consists of (1) escalating all recurring expenses at the assumed rate of inflation (6 percent); (2) calculating and summing the present value of the recurring costs at an assumed discount rate (10 percent), (3) summing the present value of all nonrecurring costs (e.g., capital expenditures) and (4) totaling the present values of all costs and determining the annual annuity value over 20 years at a 10 percent interest rate. This levelizing procedure presents the true cost associated with the time difference in compliance dates for fuel switching and installing technology and when more than one time phase for compliance is required.

2. No real increase or decrease in the cost of equipment, coal or transportation has been assumed, except for the "demand push" described above for replacement low-sulfur coal.

3. In legislation with reductions in two or more phases, the compliance strategies are (a) substitute coal for all phases, (b) substitute coal for the initial phases and retrofit scrubbers for the final phases, and (c) retrofit scrubbers for all phases. The most cost effective strategy is selected by comparing the present value of each strategy for 20 years.

The CHAIRMAN. Thank you very much, Mr. Farrand. We appreciate your testimony.

Next we will hear from David O. Webb, who is Senior Vice President for Policy and Regulatory Affairs of the Gas Research Institute.

STATEMENT OF DAVID O. WEBB, SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS, GAS RESEARCH INSTITUTE

Mr. WEBB. Thank you, Mr. Chairman. I appreciate the opportunity to appear today to present GRI's testimony on the acid rain provisions in S. 1630 and specifically on its impact on clean coal technologies.

GRI will also summarize opportunities for reducing acid rain precursors primarily in Phase I by using natural gas in combination with coal through technologies such as gas reburn and gas cofiring. These technologies are cost effective interim options that should be included as part of the national strategy for achieving emissions reductions of acid rain, precursors of SO_2 and NO_x.

GRI is an independent not-for-profit research and management organization which has a $183 million per year budget. We conduct research on behalf of our 314 members and customers.

As a matter of policy, GRI supports the efforts of Congress and the Federal Government to address clean air issues through comprehensive legislation. We think flexibility should be central to any legislation. Technology options should not be specified. States and electric utilities should be allowed to determine the most cost effective way to meet new emissions standards. Emissions trading should be encouraged.

More specifically, states and utilities should not be subject to either subsidies for specific technologies or mandates that specific technologies or fuels be used. Provision should be included in the legislation to encourage utilities to deploy emerging clean coal technologies.

GRI also endorses and encourages passage of cofiring legislation introduced last year by Senators Ford and Bingaman, S. 1848. The urgency of addressing clean air issues requires consideration be given to incorporating some of the provisions of this legislation in any Clean Air Act amendments.

GRI with industry and government participation is currently conducting R&D at a level of about $15 million a year on numerous cofiring technologies to utilize the clean burning characteristics of gas to mitigate environmental problems associated with coal combustion. Research indicates significant efforts to optimize the use of gas with coal to help produce NO_x and SO_2 emissions. Laboratory tests have indicated we may be able to reduce NO_x emissions by 60 percent and SO_2 emissions by 50 percent.

Without cofiring or similar low cost near term clean coal retrofit options, electric utilities could be left with no choice but to phase out older but still useful electric power plants or to make exceptionally large capital investments in scrubbers for these plants. Either option significantly increases the cost of electricity.

In addition, cofiring and reburn with gas would allow existing power plants to continue to burn high sulfur coal. Thus, gas cofiring and reburn technologies offer many electric utilities the options to meet Phase I emissions standards while continuing to use their existing coal supplier and utilizing only 10 or 15 percent gas in combination with this coal.

One of the central questions we always get asked when talked about using gas as one of the options for reducing acid rain precursors is is there an adequate supply to meet the demand. GRI projects that there is an adequate supply.

Our analysis would indicate that the most probable range of increased market demand for gas reusing reburn, cofiring technologies on a wide basis in phase I would be about .5 TCF per year.

The maximum amount that could be used is 2.2 trillion cubic feet per year. You can only achieve that if you mandated that 15 percent of the fuel input at every coal-fired power plant in the country had to burn gas. That is not going to happen. We are not proposing that you mandate fuel. But that gives you an idea of the range.

The GRI projection is supported by a recent DOE study, an assessment of the natural gas resource base in the United States that shows that the technical recoverable gas resource base of 1,059 trillion cubic feet exists in the lower 48 states.

Moreover, the DOE study show that 580 trillion cubic feet of gas in this total is judged to be economically recoverable with advanced technology at costs of $3 per million cubic feet at the wellhead in 1987 dollars. That would be about $3.25 at today's dollars.

Therefore, it is clear there is no absolute resource limitation on increasing annual production to meet new gas markets. It might be creative application such as coal firing or reburn.

Specific proposals and recommendations that the GRI would make regarding the legislation to benefit the clean coal technologies are as follows.

First, the President's proposed bill include language that allows a utility that participates in advanced clean coal technology demonstration program an exemption to the new source performance standards. This exemption is required to ensure protection against a plant having to meet more stringent clean air standards than it currently has to meet simply because it participated in a clean coal program in the DOE project.

Second, there should be a minimum 5-year extension of phase II compliance deadlines with new admissions limitations for plants employing either emerging, repowering or retrofit clean coal technologies.

DOE's round three clean coal projects which Ben talked about earlier emphasize both repowering and retrofit technology options included in the projects selected are those that use retrofit technologies such as gas reburn and coal firing. Therefore, we urge that the 5-year extension apply not only to repowering as in the current bill, but also apply to all retrofit technologies demonstrated as part of the DOE's clean coal program.

Further, we urge that natural gas cofiring and reburn be expressly identified among the retrofit technologies eligible for the extension.

Third, in the area of clean coal the administration's bill proposed clean air amendments—the administration's bill and proposed Clean Air Act amendments include a section that established regulatory incentives for demonstration of emerging clean coal technologies. These incentives were to be administered by FERC at a 5-year demonstration program life, and they would not apply to more than four units of each technology class. Therefore, it was a very limited incentive to encourage widespread demonstration of these clean coal technologies that should be included in any legislation.

Two other recommendations. We think any final legislation should retain the provisions currently in S. 1630 that allow plants to exchange allowances for NO_x and emissions reductions for allowances for SO_2 emissions, a ratio of exchange is currently proposed of about 1.5 units NO_x for one unit of SO_2 is reasonable and should be retained.

Finally, the legislation should retain the provisions in S. 1630 to allow emissions reductions allowances to be marked between utility systems and from a current year to a future year.

Also, we think that the two-phased SO_2 reduction program as proposed in 1630 should be retained in any legislation. Consideration should be given to having the phase I compliance deadline established 5 years after the enactment of the legislation rather than an arbitrary date that was picked when the legislation was submitted.

Finally, Mr. Chairman, anticipated growth, the new electric power generation is expected to be partly met from non-traditional sources. Therefore, the natural gas industry has endorsed your proposal to amend the public utilities holding company and to facilitate that activity.

However, many developers of these independent sources of generation are concerned that emissions allowances necessary to operate will be unavailable to them. S. 1630 attempts to address this problem by reclaiming 2 percent of the allowance for EPA to sell.

The gas industry is concerned that this may be an insufficient number. We think consideration should be given to getting inputs from these independent producers on what type of an allowance or system would be most equitable to allow them to fully participate.

In conclusion, natural gas, the cleanest burning fossil fuel, has the potential to make a significant contribution to reducing acid rain precursors in both existing and new utility power plants. Therefore, final legislation to amend the Clean Air Act should be fuel and technology neutral, should establish realistic deadlines for compliance with both phases of the new emissions standards, should recognize 5-year extensions for compliance deadlines for plants employing either repowering or retrofit emerging clean coal technologies and should provide the greatest flexibility to the individual utility executives in states that must meet these new requirements.

Thank you very much, Mr. Chairman. I will be glad to answer any questions at a later time.

[The prepared statement of Mr. Webb follows:]

TESTIMONY OF DAVID O. WEBB
SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS
GAS RESEARCH INSTITUTE
BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES
JANUARY 24, 1990

I appreciate the opportunity to appear before you today to present the Gas Research Institute's (GRI) testimony on the acid rain provisions of S. 1630, the Clean Air Restoration and Standards Attainment Act of 1989, which is currently being considered by this Committee and Congress. Specifically, I have been asked to comment on how this legislation affects opportunities for burning natural gas in combination with coal through technologies such as natural gas cofiring and reburn. These technologies are being considered as part of a national strategy for achieving emissions reductions of acid rain precursors (SO_2, NO_x). I will also comment on the acid rain provisions of the Administration's proposed clean air legislation.

GRI is an independent, not-for-profit scientific research organization that plans, manages, and finances a cooperative research and development (R&D) program of $183 million for the benefit of its 314 members (gas distribution companies, producers, gas pipelines, municipals) and their customers. The R&D program is implemented through contracts with research organizations, engineering firms, universities, energy companies, and manufacturers. Approximately 10 percent of GRI's annual R&D budget is cofunded with the federal government, and an additional 10 percent of the annual research budget is coordinated with the federal government.

As a matter of policy, GRI supports the efforts of Congress and the Federal Government to address clean air issues through comprehensive legislation. Flexibility should be central to any legislation; states and electric utilities should be allowed to determine the most cost-effective ways to meet new emissions standards. More specifically, states and utilities should not be subject to either subsidies for specific technologies or mandates that specific technologies or fuels be used. Provisions should be included in the legislation to encourage utilities to deploy emerging clean coal technologies.

GRI endorses and encourages passage of the cofiring legislation introduced last year by Senators Ford and Bingaman (S. 1848) and Congressman Regula (H.R. 1706). The urgency of addressing clean air issues requires consideration be given to incorporating the provisions of the cofiring legislation in the Clean Air Act amendments. I will be addressing specific recommendations for these amendments later in my testimony.

GRI, with industry participation, is currently conducting R&D on numerous technologies that utilize the clean burning characteristics of gas to mitigate environmental problems that are addressed in the proposed clean air legislation. GRI is also participating in field tests of advanced clean coal technologies through the Department of Energy's (DOE) Clean Coal Technology program, and GRI is currently cofunding three of the projects that have been selected. Continued development of these technologies is not only of interest to the gas industry specifically but also represents good energy policy for the nation in general. In the areas covered under the pending legislation, GRI has a 1990 R&D budget of approximately \$18 million for developing light-duty engines for natural gas vehicles in fleet use, for developing a natural gas engine for heavy-duty vehicles such as buses and garbage trucks, and for demonstrating the possibility of using small amounts of natural gas with coal for emission control through cofiring and reburn technologies.

GRI CLEAN AIR R&D INITIATIVES

GRI's research on emission control technology is guided primarily by the recognition that natural gas can be combusted with coal as one cost-effective approach for existing coal-fired boilers to meet present and anticipated clean air regulations. The R&D addresses improving existing gas-using technologies such as cofiring, as well as developing emerging and advanced gas technologies such as reburn. In most cases, research undertaken at GRI has a near-term focus with industry participation to ensure rapid application.

GRI's R&D focus is gas use with other fuels, primarily coal, to reduce emissions from large fossil fuel boilers. Natural gas can play an expanded and important role in addressing growing concerns about air quality in general and acid rain in particular. Research includes significant efforts to optimize the use of gas with coal to help reduce NO_x and SO_2 emissions from fossil-fuel-fired utility and industrial boilers. Major attention is currently directed at the near-term option of testing cofiring techniques.

Three cofiring technologies are under development:

1. Basic Cofiring. Gas is concurrently fired in the primary combustion zone with other fuels to trim SO_2, NO_x, and particulate emissions.

2. Gas Reburn. Gas is combusted in a staged manner creating a secondary combustion zone to achieve 50 to 60 percent NO_x emission reductions.

3. Gas Reburn/Sorbent Injection. Gas reburn is mated with sorbent injection technology to provide 50 to 60 percent NO_x and SO_2 reductions.

In addition to emissions control, these cofiring technologies may simultaneously help provide solutions to a range of boiler operational problems. These potential operational benefits include mitigation of capacity derating problems (helping older plants operate at or near their rated design), improved unit availability, improved load following, increased coal vendor flexibility (widening the range of coals that can be burned), slagging/fouling control, and other benefits that can be of economic value to utilities. Understandably, boiler operational benefits and the associated value of these benefits are highly site specific, and the annualized value to a boiler operator will vary depending on how frequently the benefit is realized. Nevertheless, opportunities potentially exist for the incremental cost of gas to be significantly offset by the value of operational benefits alone.

In 1988, 1989, 1990, GRI will spend approximately \$17 million on R&D in cofiring technologies. For 1991 through 1994, GRI plans to spend approximately \$15 million to further the R&D. GRI anticipates matching the \$15 million with additional cofunding from federal, state, and industrial partners resulting in a total annual effort of approximately \$10 million.

As an example of the R&D and its potential contribution to reducing emissions, Duquesne Light Co., Consolidated Natural Gas Co., and GRI recently completed a cofiring field study at Duquesne's Cheswick Powerplant near Pittsburgh. The field test documented a 25 percent reduction of NO_x emissions using 6 to 10 percent natural gas cofiring with local coal. The test also documented greater than proportional reductions of both NO_x and SO_2 emissions under certain operating conditions.

Based on initial test results, cofiring has the potential to be a cost-effective means for electric utilities with older powerplants burning local high sulfur coals to achieve emissions reductions. Without cofiring or a similar low cost near-term retrofit option, electric utilities could be left with no choice but to phase out still useful older powerplants or to make exceptionally large capital investments in retrofitting such plants with scrubbers. Either option would significantly increase the cost of electricity. In addition, cofiring would allow existing powerplants to continue to burn high-sulfur coal. Thus cofiring gives electric utilities the option to continue to use their existing coal supplier by burning 10 to 15 percent natural gas with coal.

Although basic cofiring offers utilities highly cost-effective emissions trim and operational benefits, gas reburn promises to achieve even greater emissions reduction at low capital cost. The technology is applicable to all furnace designs. The term "gas reburn" refers to the injection of natural gas into the upper furnace region of a boiler to produce a fuel-rich zone that reduces NO_x emissions. Overfire air is added in a final burnout zone to complete the overall combustion process. In this reburn zone, much of the NO_x present (50 to 60 percent or more) is converted to elemental nitrogen. Pilot tests indicate that a majority of cyclone boilers could successfully apply this technology in order to reduce their NO_x emissions. Pilot scale tests indicate that 20 percent natural gas cofiring in a reburn application can reduce NO_x emissions by 60 percent and SO_2 emissions by 20 percent. When mated with sorbent injection technology to increase SO_2 capture, gas reburn has the potential to achieve a 50 percent reduction in SO_2 emissions. If these laboratory results can be duplicated in upcoming field tests, then the role of natural gas as a cost-effective option for reducing acid rain emissions will become a reality. This is the objective of GRI's R&D program.

NILES PLANT COFIRING PROJECT

A reburn project currently in progress is located at the Ohio Edison's 108 MW cyclone boiler at the Niles Powerplant to demonstrate reburn technology. The cost is estimated to be $10.7 million. GRI, the Electric Power Research Institute, Consolidated Natural Gas, Ohio Edison, the Environmental Protection Agency, the Ohio Coal Development Office, and the Department of Energy (outside the Clean Coal Technology program) are all cosponsors.

Reburning is uniquely well suited as an in-furnace NO_x reduction technique for cyclone-fired boilers, which produce significantly more NO_x than wall-fired or tangentially fired boilers. Cyclone-fired boilers contribute about 21 percent of the NO_x emitted by pre-New Source Performance Standards (NSPS) coal-fired units even though cyclone-fired boilers represent about

14 percent of the pre-NSPS coal-fired generating capacity. Since the cyclone combustor cannot tolerate significant changes in its operation without the possibility of creating other problems, the cyclone combustor is limited to an in-furnace NO_x reduction technology. The only operation change required with reburn is that the primary fuel-feed rate be reduced in the primary combustor with an equivalent amount (on Btu basis) of fuel injected in the reburn zone, usually not more than 20 percent of the total fuel input. The excess air, and therefore the air/fuel stoichiometry within the cyclone, can be held constant, thereby lessening the potential for cyclone operational problems. Based on past research, the conservative expectation is that NO_x will be reduced in a cyclone-fired boiler by at least 50 to 60 percent.

The system design and fabrication phases of the Niles plant project have been completed. Plans are to install the reburn system during the regular boiler maintenance outage scheduled for May 1990. Baseline tests and parametric tests of the reburn system will follow the installation of the system for approximately 6 to 9 months. The six-month performance test is scheduled to start in the spring of 1991. The project will be completed in April 1992.

GRI/DOE CLEAN COAL TECHNOLOGY PROJECTS

GRI is currently cofunding three of the Clean Coal Technology projects that have been selected in the first three solicitations of the DOE program. The first project, selected under Round I, is to demonstrate gas reburning-sorbent injection (GR-SI) at two utilities in Illinois. This project is being sponsored by Energy and Environmental Research Corporation (EERC). The second project, selected under Round III, will evaluate gas reburning and low-NO_x burners of a wall-fired boiler. This project is also being sponsored by EERC. The third project, also selected under Round III, will demonstrate the NOXSO SO_2/NO_x removal flue gas cleanup system. This project is being sponsored by the MK-Ferguson Company.

OVERVIEW OF THE ROUND I GAS REBURN/SORBENT INJECTION DEMONSTRATION PROGRAM

EERC's ongoing project, "Enhancing the Use of Eastern and Midwestern Coals by Gas Reburning-Sorbent Injection," was one of the first nine projects selected by DOE for demonstration in Phase I of the Clean Coal Technology program. The estimated total cost of the program to demonstrate GR-SI is $30 million over three to four years. GRI is providing $10 million, and the Department of Energy and Natural Resources of the State of Illinois is cofunding $5 million. DOE, through the Clean Coal Technology program is providing $15 million.

Three host sites were originally planned to participate in the program. However, the project has been rescoped and now includes only two host utility sites. These sites will provide full-scale, operational data on a tangential coal-fired boiler and a cyclone coal-fired boiler, which are typical of pre-NSPS designs and comprise over half of the U.S. coal-fired generating capacity. These types of units produce 12 million tons of SO_2 per year. Initial tests will be conducted using Kentucky and Illinois coals. Plans are being considered for testing other coals. Each host site will be tested for a range of conditions culminating in a one-year, long-term evaluation.

Like most electric utility technologies, applications of gas reburn and reburn combined with sorbent injection have to be assessed on a site-specific basis. Nevertheless, the best opportunities for applying GR-SI are projected to occur on medium- to smaller-size units (less than 500 MWs) typically built in the 1950s and 1960s. Therefore, the primary major market for GR-SI is in the Eastern and Midwestern coal-producing states: Kentucky, Pennsylvania, West Virginia, Ohio, Illinois, and Indiana. These states have 47 percent of the total installed boiler capacity, or a little over 88,000 MW. GR-SI represents a technology that provides utilities with a cost-effective means of retrofitting and operating older existing units until these older units are replaced with new generating capacity. GR-SI is one environmentally acceptable solution for older powerplants burning high-sulfur coal.

OVERVIEW OF THE DOE ROUND III GAS REBURNING AND LOW NO_x BURNERS ON WALL-FIRED BOILER

EERC's second project, "Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler," will be a 50/50 cost-shared venture with a total estimated cost of $14.5 million. The project will be located at Public Service Company of Colorado's (PSCo) Cherokee Station Unit 3 in Denver.

This project will demonstrate the combination of gas reburning and low-NO_x burners on a 172 MW wall-fired utility boiler. Observations made to date suggest that gas reburn may significantly enhance the performance of low-NO_x burners, thereby resulting in greater NO_x reductions. Prior to startup, PSCo will evaluate plans to install a sorbent injection system to be fully operational during the field evaluation. If a sorbent injection system is installed, the test will provide a unique opportunity to evaluate the integration of three advanced emission control technologies: gas reburning, low-NO_x burners, and sorbent injection.

The project will be conducted in three phases. In the initial phase, EERC's design methodology will be used to design the equipment and prepare the plans to complete the testing. A baseline test will be conducted. In Phase 2, the gas reburning and low-NO_x burners will be installed on the unit. Phase III is a comprehensive assessment of the performance of the combined emission control technologies in commercial service. Phase III includes three months of optimization tests followed by 12 months of operation by the utility operators in normal commercial service. A comprehensive series of emissions, boiler performance, and durability measurements will be made to establish a data base for subsequent commercial applications.

Cofunding for this project will be provided by EERC and PSCo as well as the Gas Research Institute, the Electric Power Research Institute, and Colorado Interstate Gas Company. The project is scheduled to commence in late 1990 and the field evaluation will be completed in November 1993.

OVERVIEW OF THE ROUND III NOXSO SO_2/NO_x REMOVAL FLUE GAS CLEANUP SYSTEM

In MK-Ferguson Company's proposal, the NOXSO process will be retrofit to a 115 MW coal-fired boiler at Ohio Edison's Niles station. The NOXSO process, which uses natural gas to regenerate a patented sorbent material, has the goal of removing 97 percent of the SO_2 and 70 percent of the NO_x from the flue gas exhausted into the atmosphere. This is equivalent to removing 90 percent of the combined weight of the acid rain pollutants, but the process is very capital intensive. The project will be conducted by the team of MK-Ferguson, W.R. Grace and Company, and NOXSO Corporation. In addition, cofunding will be provided by the Gas Research Institute. The total cost of the project is estimated at $66.25 million and will be cost shared 50/50 between government and private industry.

COFIRING PROMOTION ACT OF 1989 (S. 1848)

In addition to DOE's Clean Coal Technology demonstrations, other opportunities exist for the near-term development of cost-effective retrofit emission control technologies. GRI encourages the passage of S. 1848, introduced by Senators Ford and Bingaman to establish an R&D program to demonstrate cofiring and reburn for retrofit applications within the next three to four years. If this legislation is passed and implemented, the test results would produce data on these technologies early enough for utilities to make decisions on methods of emissions reductions within the time frames being considered in the Clean Air Act amendments. This legislation (which authorizes the Secretary of Energy to administer a three-year, $27 million 50/50 cost-sharing program for the research, development, and demonstration of cofiring technologies) is urgently needed and should be considered as part of the Clean Air Act amendments.

NATURAL GAS RESOURCE BASE

Natural gas can play a significant role in helping the nation use its vast coal supply in an environmentally acceptable manner. Natural gas is our nation's cleanest burning fossil fuel. Its combustion emits virtually no particulates, sulfur oxides, or reactive hydrocarbons and produces far lower emissions of carbon dioxide per unit of energy than coal or oil. Used selectively with coal, relatively small quantities of natural gas could contribute significantly to protecting our air quality at a low cost. Given the size of the gas resource base and the economics of gas production, the competitive position of gas relative to other environmental control options should remain favorable. In addition, a million-mile pipeline and distribution network are already in place. Thus cost-effective solutions to using coal cleanly are both possible and practical by selectively using natural gas.

Despite assurances, many utility executives are concerned about the long-term availability of natural gas to meet the incremental demand that would be created by the large-scale adoption of gas cofiring and reburn technologies to meet new clean air requirements. The question of natural gas availability (how much at what price), is not exclusively a matter of geology.

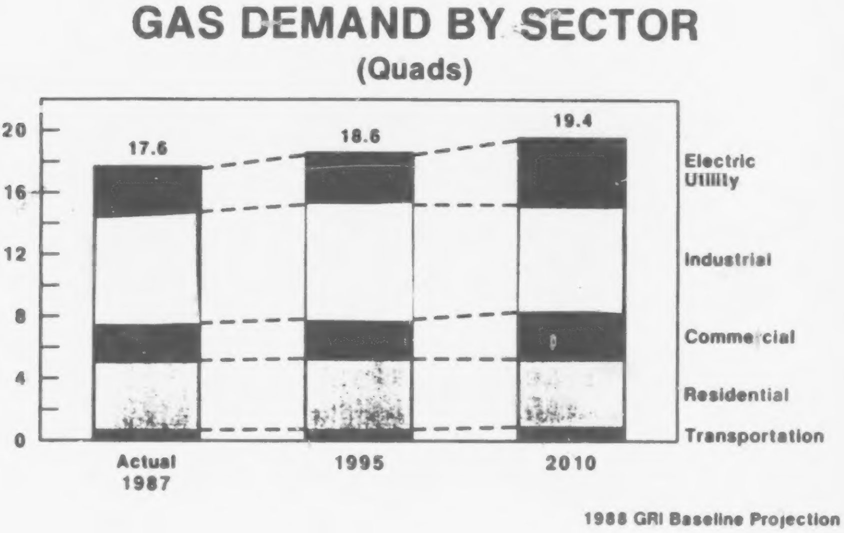
The price and quantities of delivered gas will depend upon two principal factors:

1. The geology that ultimately makes the resource available and dictates part of the price, and

2. A flow of investment into the exploration, production, and transportation of gas to the user.

According to GRI's 1989 Baseline Projection of U.S. Energy Supply and Demand to 2010, natural gas consumption based on current uses will grow at an average annual rate of 0.4 percent for the next ten years. This consumption growth represents a stable market outlook as illustrated in Figure I.

Figure I



The projection anticipates the availability of a few selected new gas technologies resulting from GRI's program for which technical characteristics, economics, and market entry dates are reasonably predictable. The projection does not reflect the entire potential impact of gas R&D and is in that sense a baseline future for the evaluation of potential strategies. Furthermore, this projection includes no estimate of potential demand for natural gas to serve new environmental functions, such as powerplant emission control.

It has been determined in the GRI baseline projection that adequate sources of gas will be available to meet the additional demand for natural gas if natural gas is used widely for emissions control purposes. The maximum additional demand for gas for emissions control in coal-fired electric utility plants is 2.2 quads per year. This annual level of demand assumes that natural gas would comprise 15 percent of the fuel mix of every coal-fired electric utility plant in the United States, an occurrence that will not happen. In more realistic terms, in economic competition based on coal and gas prices, indications suggest that actual market penetration would range somewhere between 0.2 and 0.8 quad. Estimated consumption of natural gas in 1988 was 18.1 quads. Current production is running slightly below that at 17.5 quads annually with the balance of the demand met by other sources; i.e., storage, supplemental gaseous fuels, and natural gas imports (see Table I). The capability exists for additional domestic production.

TABLE I
1989 GRI Baseline Projection
of Gas Supply Trends
(Quads)

	Actual 1988	1995	2000	2010
Lower-48 Production	15.6	15.0	16.1	15.6
Alaskan Production	0.2	0.2	0.2	1.5
Pipeline Imports	1.3	1.9	1.9	1.8
LNG Imports		0.5	0.8	1.0
Coal Gas	0.1	0.1	0.1	0.1
Other Gas	0.1	0.2	0.2	0.2
Total	17.3	17.9	19.3	20.2
Lease & Plant Fuel	1.2	1.1	1.2	1.2
Total Supply	18.5	19.0	20.5	21.4
Losses & Exports	0.4	0.4	0.4	0.4
Total	18.1	18.7	20.2	20.9

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*Numbers may not add due to rounding.

The claims that domestic gas production can be increased at competitive costs is supported by a recent DOE study, An Assessment of the Natural Gas Resource Base of the United States (May 1988), that shows a technically recoverable reserve and resource base of 1,059 Tcf of natural gas exists in the Lower 48 states (See Table II). This resource base is made up of proved reserves, inferred reserves, and resources. The recovery of gas in the resources category requires discovery and development of new technology, some using improved understanding of reservoir geometry. Of that, 800 Tcf exists or is estimated to exist in conventional reservoirs. More than half of the total resource evaluated in the Lower-48 states, or 583 Tcf of gas, is judged economically recoverable at less than $3/Mcf (wellhead prices, 1987$). An additional 174 Tcf of gas is judged economically recoverable in a price range of $3/Mcf to $5/Mcf.

TABLE II
Comparison of Recent Estimates of U.S. Natural Gas Resources
(Tcf)

	DOE	PGC	GRI
Lower-48 Proven Reserves	159	154	159
Undiscovered Resources	900	678	978
Total Lower-48	1059	832	1127
Alaska	129	152	N/A
Total U.S.	1188	984	N/A

This table compares several reasonably contemporary, authoritative estimates of the U.S. natural gas resource base. If the estimates are normalized regarding scope, significant differences among the technical judgments of the remaining recoverable resource base can still be found, even in the most intensively explored and developed areas. Furthermore, it should be recognized that the definitional and scope differences, the differing perceptions of the economic and technological constraints that should be applied, and the appropriate treatment of the less conventional resources do constitute real differences in opinion among the analysts who authored the studies concerning the way in which the remaining recoverable resources should be viewed.

The conclusion, however, is strong agreement that extensive resources still exist, even in the mature U.S. situation, that can be developed at competitive prices. The amount of natural gas constitutes about 50 years of supply at current production levels even if Canadian and other Western hemisphere supplies are ignored.

It is clear that there is no absolute resource limitation on increasing the annual production of natural gas for U.S. markets for the foreseeable future. If new applications such as cofiring or reburn were to enter the marketplace, they could be accommodated. This is not entirely a speculative statement. For example, during the past few years production of coalbed methane has arrived at the point where it is a candidate to move up to the "conventional practice" part of the table. About 200 coalbed gas wells were drilled in 1987, 500 wells in 1988, and the number may have doubled in 1989. GRI's activities in developing and disseminating technical data have played a prominent role in increasing the number of wells drilled.

The GRI baseline projection does not include any estimate of the potential contribution of incremental gas recovery from conventional reservoirs using more intensive production techniques such as secondary gas recovery. GRI and DOE have a cooperative R&D venture to test the practical aspects of theory and practice to non-associated gas fields. The potential impact of this extension of "conventional practice" could result in 50 to 100 Tcf of additional cost-competitive gas in the next 10 to 15 years.

In summary, adequate economic opportunities exist to meet the projected growth in demand for gas, including emissions control market opportunities, at cost-competitive prices.

RECOMMENDATIONS FOR LEGISLATION

1. The President's proposed bill allows a utility which has made physical or operational changes to existing facilities for the sole purpose of installation, operation, cessation, or removal of an advanced clean coal technology demonstration project an exemption to the New Source Performance Standards. This exemption is only allowable as long as the project does not result in an increase of pollution relative to the facility's predemonstration levels as measured by the facility's potential to emit any pollutant regulated under the Clean Air Act. The bill reported out of the Senate Environment and Public Works Committee does not contain this exemption. For many utilities to freely participate as host sites and cofunders in Clean Coal Technology demonstrations, this exemption is required to ensure protection against a plant's having to meet more stringent clean air standards simply because of its participation in an emerging clean coal demonstration even if the demonstration does not meet economic or technical objectives and is removed after the field test.

2. Repowering units with emerging clean coal technology affords substantially increased capacity with lower emissions rates. In recognition of the contribution of emerging clean coal technologies, there should be a five-year extension of Phase II compliance with new emissions limitations for plants employing these technologies. Since it is also in the national interest to encourage the utilization of those natural gas retrofit technologies that reduce SO_2 and NO_x emissions during the combustion of coal being demonstrated in DOE's Clean Coal Technology Demonstration program, we urge that the extension also apply to all retrofit technologies demonstrated as part of DOE's Clean Coal Technology program. Further, we urge that natural gas cofiring and reburn be expressly identified among the technologies eligible for the extension.

3. The Administration's proposed Clean Air Act amendments included a section that established regulatory incentives for emerging clean coal technologies. The FERC is to establish these regulatory incentives. The incentives are necessary to assure the utilities that there will be consistent regulatory policy regarding recognition of the inherent risk and recovery of costs from innovative emission control technologies. The regulatory incentives should be included in final legislation to encourage widespread use of cost-effective emerging clean coal technologies.

4. Any final legislation should retain the provisions of S. 1630, new section 403(c), that allow sources to exchange allowances for NO_x emissions for allowances for SO_2 emissions and to apply allowances for one pollutant to emissions for the other. The ratio of exchange proposed--1.5 units of NO_x for 1 unit of SO_2--is reasonable. This exchange provision is essential to give the local utility the most cost-effective options to meeting the new acid rain regulations.

5. Final legislation should retain the provisions in S. 1630 to allow emissions reduction allowances to be marketed between utility systems and from a current year to a future year.

6. The two-phase SO_2 reductions program as proposed in S. 1630 should be retained in any legislation. Consideration should be given to having the Phase I compliance deadline established five years after enactment of legislation.

7. Anticipated growth in new electric power generation is expected to come from non-traditional utilities. In recognition of this important new source of power generation, the natural gas industry has endorsed Senator Johnson's proposal to amend the Public Utilities Holding Company Act to facilitate that activity. Many developers of these sources of generation are concerned that emission allowances necessary to operate will be unavailable to them because utilities will strictly control emission credits. S. 1630 attempts to address this problem by reclaiming 2 percent of the allowance for EPA to sell. The gas industry is concerned that this may be an insufficient number to allow this new power source to be fully developed. We believe emission allowances for non-traditional utilities may present an significant problem and believe the Committee should take steps to provide an equitable solution that would allow IPPs to compete for new power generation capacity.

CONCLUSION

Natural gas, the cleanest burning fossil fuel, has the potential to make a significant contribution to reducing acid rain precursors (NO_x, SO_2) in both existing and new utility powerplants. Therefore, final legislation to amend the Clean Air Act should be fuel and technology neutral, should establish realistic deadlines for compliance with new emissions standards, should recognize five-year extensions for compliance deadlines for plants employing emerging clean coal technologies, and should give the greatest possible flexibility to the individual utility in meeting the new requirements.

The CHAIRMAN. Thank you, Mr. Webb.

Finally, we have Mr. Richard Ayres, who is Senior Attorney with the Natural Resources Defense Council on behalf of the National Clean Air Coalition. Mr. Ayres.

STATEMENT OF RICHARD E. AYRES, SENIOR ATTORNEY, NATURAL RESOURCES DEFENSE COUNCIL, ON BEHALF OF THE NATIONAL CLEAN AIR COALITION

Mr. AYRES. Thank you, Mr. Chairman. I appreciate the opportunity to be here today to testify before the committee with respect to the acid rain provisions of S. 1630.

I think it comes as no surprise to this committee that the National Clean Air Coalition supports the acid rain control provisions in this bill, this bill being S. 1630, including the 10-million-ton reduction and 10-year schedule and the cap on emissions.

We also believe that the allowance trading system is a workable sound program. We are aware that others have proposed variations on this program designed to provide assurance to those who are potentially affected by shifts in coal markets or rate increases. Proposals of this sort could also, if properly crafted, achieve the environmental objectives that we have outlined.

With respect to these regional concerns, what is needed clearly is a spirit of cooperation in the national interest, and that is what we would most encourage.

Now, I would like to turn to the impact of the bill on the west where we have some serious concerns. This bill reflects a consensus or an emerging consensus that emissions of acid rain causing pollutants need to be substantially curtailed.

It is, therefore, ironic that the bill would permit increased emissions of the same pollutants in the West. These increases would be allowed by four provisions outlined in my written testimony. One is the so-called clean states exemptions that has been discussed already. A second is the provision for 20 percent bonus allowances for plants that emitted a rate lower than 1.2 pounds when the program being, and the other two are changes in existing laws, in the existing Clean Air Act to provisions which have assured that new power plants built in the West will be and have been very clean.

Environmental concerns regarding sulphur and nitrogen oxide emissions in the West include both acid rain damage to sensitive mountain ecosystems and further degradation of visibility. Western visibility is a unique world class resource. It is worth billions of dollars in tourism as well as uncounted benefits in terms of the lives of those who live in the West.

Thus, we would urge the Senate to eliminate the clean state exemption and drop the proposed amendments that would change the existing law with respect to percentage reduction in BACT.

The argument for retaining the bonus allowances is based on a concern that has been expressed here very eloquently today that there will be limits placed on growth in clean states at utilities with low emissions rates. But we feel that if this proposal is retained, if some sort of bonus system is retained, the bonuses should be available to utilities which have already actually controlled emissions to the maximum feasible extent and also in states where changes have been made to the regulatory system to assure that least cost planning is in place and where the utility has complied with the least cost planning and has reached the conclusion and can demonstrate that the power plant it wants to build is indeed the least cost alternative for satisfying the demand that it faces.

The CHAIRMAN. What does cost have to do with it? I mean, why your interest in cost?

Mr. AYRES. Well, one of the advantages of the cap, Senator Johnson, is that it will encourage utilities to look harder at the least polluting options; namely, more energy efficiency, and there are some others as well, but energy efficiency is obviously—since it does not pollute at all, it obviously becomes more attractive under the cap.

Least cost planning also has a tendency to encourage investments in conversations where they are more cost-effective than investments in powerplants, and we believe there are many investments of that sort out there to be made.

The CHAIRMAN. Well, I was just curious as to why you would focus on cost as opposed to environmental concerns.

Mr. AYRES. Well, we are focusing on both. What I am suggesting is the argument for the lead bonus allowances is the notion that there will be a constraint on utilities that face demand and need to build new facilities, and the argument is made because some people say well, we have cleaned up our state, we have cleaned up all the plants in our state or all the plants in our utility system. That is an argument which some systems can make much more convincingly than others.

And so what I am suggesting is, first, let us make sure that the utility that wants bonuses allowances can, in fact, make the argument that it has cleaned up as much as it can and, second, can, in fact, make the argument that it has explored other nonpolluting ways of satisfying its demand problem and only after doing that exploring all the less costly ways as it reached the conclusion that it has to build a new powerplant.

So, the two notions work together to drive the utility toward using increasing pollution as a last resort rather than a first resort, and we think that is the appropriate policy to follow with respect to western coal.

The CHAIRMAN. I heard you. It just seems to me that least cost ought to be a concern of the PUC and not the environmental group. The environmental groups ought to say whatever you do to clean up the air, we want to measure you by that and let the PUC worry about what is most cost effective.

Mr. AYRES. Well, least cost planning has been one of the major objectives of many of the environmental—of many in the environmental community, including my organization because of the feeling that on a level playing field, less environmentally damaging means that dealing with demand will emerge as well. So, that is why the interest.

Let me turn, then, to clean coal technology. As S. 1630 provides special treatment for utilities that employ clean coal technology to repower existing coal-fired units, they would be given until the year 2004, as has been discussed here.

We believe the year 2000 date which is in the bill for phase II compliance already constitutes a generous extension for clean coal technology and for other compliance methods. Accordingly, we think extra extensions for clean coal technology to the year 2004 are unnecessary and inappropriate.

Our experience already in the last 20 years under the Clean Air Act has demonstrated convincingly that technological innovation is more likely to occur in response to ambitious goals, not in response to extended deadlines. The schedule for demonstrating clean coal projects published by the Department of Energy shows that virtually all projects will complete testing sufficiently in advance of the year 2000 to allow utility managers to select a clean coal technology for compliance and still meet the year 2000 deadline. More delays will provide for more procrastination, not expeditious efforts to make it work.

Moreover, since repowering projects involve taking an existing boiler out of service, the bill even without an extension would not require a company to complete installation of clean coal technology by the year 2000. Rather, the company would be in compliance if it took its existing unit out of service by the year 2000 to do the repowering project.

In some cases this could occur a year or more before construction and installation of the repowering unit was complete. If the Senate continues to provide extra extensions for repowering, we would urge the addition of a requirement for the company to pay back the excess emissions resulting from the extension. While this would not be a complete compensation for the environmental cost, since a reduction would occur later, it would limit those costs and would create an incentive for companies to minimize their excess emissions during the extension period.

A very important provision in both the Administration bill and S. 1630 is the limitation of the extension to specified repowering technologies. We strongly oppose the broadening of that extension to other retrofit technologies.

S. 1630 appropriately did not accept a number of other exemptions from the current Clean Air Act that were included in the Administration bill.

The rejected exemptions are so broad that they would allow clean coal technology projects to operate without safeguards to prevent increases in air pollution that could pollute areas where they would be built and cause pollution problems in the national parks and wilderness areas.

We support S.1630's refusal to exempt those projects from clean air protection requirements, and urge members of this committee to support the environment committee on this issue.

Finally, we oppose the provision in the Administration bill that would exempt repowering projects from the cap on SO_2 emissions. It is not necessary because all the repowering technologies listed will have emissions that are only a fraction of the allowances of the sources they replace.

That, after all, is one of the major purposes of the repowering project.

S. 1630 rejects the Administration's unnecessary allowance. We urge members of this committee to do the same.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Ayres follows:]

TESTIMONY OF RICHARD E. AYRES
NATIONAL CLEAN AIR COALITION

BEFORE THE

U.S. SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

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Mr. Chairman, my name is Richard Ayres, chairman of the National Clean Air Coalition. I am delighted to be here this morning to offer testimony on the acid rain control program of S. 1630, the proposed Clean Air Act amendments, on behalf of the Coalition.

The National Clean Air Coalition is made up of nearly three dozen major national environmental, public health, labor, civic, and church organizations supporting a strong, revitalized federal Clean Air Act.

PRIMARY ENVIRONMENTAL OBJECTIVES

The Coalition's primary yardstick for evaluating acid rain proposals is whether they will achieve the emission reductions indicated by National Academy of Science reports issued in the early 1980's --- a halving of the 1980 emissions of sulfur and nitrogen oxides --- within a decade or less. Once these objectives have been achieved, they must be maintained by retraining, or "capping," emissions at the reduced levels.

The bill adopted by the Senate Committee on Environment and Public Works, S. 1630, meets these objectives to a reasonable approximation. As we have indicated to the Committee, we believe the bill does allow unacceptable increases in emissions in the West, a point I will return to later. Overall, we support the proposal strongly, and will work for its passage.

We have also stated our support for the basic regulatory architecture of the proposal. S. 1630 would reduce emissions in two phases. In the first phase, commencing in 1995, it would reduce emissions of SO_2 by approximately four million tons. Beginning in the year 2000, emissions from utility sources would be "capped" at 8.9 million tons per year nationally. In both phases, sources subject to emission limitations would be free to exchange these obligations with other sources through an emission trading system. In our view, the structure contained in the bill is a workable scheme for achieving the appropriate environmental goals.

We are aware of the fact that others have proposed other ways of achieving the first phase goals of the program, designed to provide assurance to those potentially affected by shifts in coal markets and/or rate increases. Proposals of this sort could, if properly crafted, also achieve the environmental objectives we have outlined.

What is apparent is that there is a need for a spirit of cooperation in the interest of addressing the environmental and public health effects of acid rain. The President has made curtailing acid rain is a matter of national priority; as with other such matters, addressing it will require statesmanship and an enlightened concern for our common natural heritage.

EMISSIONS TRADING

As I said previously, an emission cap is a crucial element in an acid rain control program. Without it, increased emissions will soon erase our pollution control gains. Without it, the emissions trading program cannot work; and its promised economic efficiency will evaporate.

Some have argued that the cap will restrain economic growth. To the contrary, there is no relationship between increased pollution and economic growth. Acid rain exists largely because so many large power plants continue to operate with no pollution controls for sulfur and nitrogen oxides. With modern pollution control methods and increasing energy efficiency, air pollution control is not a constraint on economic growth.

Those who claim the cap may constrain building new plants are simply ignoring the numbers. EPA predicts that in the absence of an acid rain program total U.S. utility SO_2 emissions will range from an increase of 1.3 million tons annually to a decrease of 1.4 million tons. With a cap in effect, even the high growth forecast would be lower than 1.3 million tons because of the better SO_2 control and greater energy efficiency. To offset whatever remaining SO_2 may be associated with new plant construction, then, industry will be able to draw on a pool of over 14 million tons of SO_2 that will still be emitted even after the rollback is completed.

Others argue that the emission trading system will not work, because the utilities will hoard the allowances provided in the bill. I believe these concerns are overblown: unlike, for example, transmission lines, no single utility will have no monopoly power over the availability of allowances for those who seek them.

To provide further assurance of a robust competitive market in allowances, however, the Coalition would support two measures that have been proposed. First, we would support increasing the reserve held by EPA, to be made available in the event that allowances could not be obtained in the market, to five per cent of allowances. Second, we would support measures to prevent anticompetitive use of allowances, such as requiring allowance holders to engage in a competitive bidding process when they seek to sell or use their initially allocated allowances, and prohibiting self dealing at below-market prices.

A market-based system will be most efficient if all major sources are included within it. Thus we oppose exempting major sources based on claims that they are relatively "clean" compared to others. A clean facility is one that adds no pollution to the environment. Other facilities are not "clean:" they merely pollute less. Under S. 1630, less polluting sources will be rewarded in the marketplace by having to obtain fewer allowances than more polluting facilities.

ENVIRONMENT CONCERNS: IMPACT ON THE WEST

S. 1630 reflects a national consensus that emissions of acid rain-causing pollution need to be substantially curtailed. It is therefore ironic that the bill would allow increased emissions in the West.

These increases would be allowed by four provisions:

- The bill includes a so-called "clean States exemption" from the limits applicable in every other State under the program. These States would be free to become "energy farms" with unlimited pollution increases.
- It provides that facilities with emissions rates below 1.2 lb/mmBtu will be issued "bonus allowances" that would authorize a 20 per cent increase in pollution.
- The bill would repeal the "percentage reduction" requirement in existing law, which assures that new power plants will not be built without pollution control technology.
- And, it would permit new facilities to claim that using low sulfur coal satisfied their obligation to install "best available control technology."

Environmental concerns regarding SO_2 and NOx emissions in the West include both acid rain damage to sensitive mountain ecosystems, and further degradation of visibility from sulfate and nitrate particulate. Western visibility is a unique, world-class resource, which attracts millions of visitors and creates billions of dollars in tourism income every year.

If significant emissions increases occur, they will impose large environmental costs. The National Park Service has concluded that emissions increases in the West pose a threat to visibility and other air quality-related values in our National Parks. Other studies have shown the extreme vulnerability of high mountain lakes to additional pollution loadings.

We believe these studies warrant a policy of preventing emission increase in the West. Existing emissions inventories indicate that there remain many opportunities for cost-effective emissions reductions at today's western power plants that can offset emissions added by greater generation. We believe that the West can have clean air and added electrical generation, and the burden of persuasion to the contrary has not been met.

Thus we would urge the Senate to eliminate the "clean State" exemption, and drop the proposed amendments to the Act's "percentage reduction" and "BACT" requirements.

The argument for retaining "bonus allowances" is based on a concern that there will be insufficient allowances to permit growth at utilities with lower emission rates. If it is retained, bonus allowances should be available only in the situation of concern. Thus bonus allowances should be available only where a utility has already controlled emissions from its own existing facilities to the maximum feasible extent, and where economical non-polluting avenues of dealing with growing demand have been exhausted.

To implement these ideas, we would provide for issuance of bonus allowances only if (1) the utility system owner has achieved at least 70 per cent reduction in emissions; (2) the utility's State has adopted regulatory reforms to reward energy efficiency investments; and (3) the utility is complying with a State least-cost energy plan and can demonstrate that construction of a new unit represents the least-cost option for balancing electrical supply and demand.

"CLEAN COAL TECHNOLOGY"

S. 1630 provides special treatment for utilities that choose to comply with the acid rain control bill by employing so-called "clean coal technology" to repower existing coal-fired units. Under S. 1630, plants repowering with clean coal technology would be given until the beginning of the year 2004 (fourteen years from now) to comply with phase two SO_2 control requirements.

We believe the year 2000 date for phase two compliance already constitutes a generous extension for clean coal technology and other compliance methods. Accordingly, we think the extra extension for clean coal technology to the year 2004 is unnecessary and inappropriate. The schedule for demonstrating clean coal technology projects published by the Department of Energy shows that virtually all projects will complete testing sufficiently in advance of the year 2000 to allow utility managers to select a clean coal technology for compliance and still meet the year 2000 deadline. Providing more delays for clean coal technology will encourage procrastination, not expeditious efforts to make clean coal technology methods work.

Moreover, since repowering projects involve taking an existing boiler out of service, the bill, even without the clean coal technology extension, would not require a company to complete installation of a clean coal technology-repowered unit by the year 2000. Rather, the company would be in compliance if, under its construction program, the existing unit was taken out of service as of the year 2000. In some cases this could occur a year or more before construction and installation of the repowered unit was complete.

If the Senate continues to provide extra extensions for repowering projects we would urge addition of a requirement for the company to "pay back" the excess emissions resulting from its extension over a period of years after it comes into compliance. While this would not be a complete compensation for the environmental costs of the extension since the reduction would occur later in time, it would limit those costs and would create an incentive for companies to minimize their excess emissions during the extension period.

A very important provision in both the Administration bill and S. 1630 is the limitation of the extension to specified repowering technologies. This limitation is designed to recognize claims that the specified technologies have somewhat longer demonstration schedules than do other clean coal technology methods that can be "retrofitted" onto existing boilers. The utility industry has urged that the clean coal technology extension be made available to "retrofit" technologies as well. Such a broadening of the clean coal technology extension would result in a major weakening of the acid rain control program and we strongly oppose such a change.

Since the definition of "clean coal technology" is extremely broad, if the extension were made available to retrofit applications virtually all phase two compliance activities could seek the extension to 2004. Such an added delay would mean much greater continued loadings of acid-rain pollutants. Nor can such added delay be justified. The retrofit clean coal technology methods are for the most part already demonstrated or will be in the next several years. There is ample time for their use before the year 2000.

S. 1630 appropriately did not accept a number of exemptions from the current Clean Air Act for clean coal technology that were included in the Administration bill. The rejected clean coal technology exemptions are so broad they would allow clean coal technology projects to operate without safeguards to prevent increases in air pollution that could pollute the areas where they would be built and cause pollution problems even in pristine national parks and wilderness areas.

For example, under §515 of S. 1490, the Administration bill, a large new coal-fired power plant could be built at any existing plant site in the country and be wholly exempt from federal New Source Performance Standards no matter how much pollution would be added by the source.

Section 515 contains other exemptions from new source review programs -- programs that are designed to protect against public health problems and damage to pristine areas. Under these exemptions a clean coal technology project could result in enormous increases in actual emissions from an existing plant and not be subject to any analysis to determine whether the added pollution would threaten public health, national parks, or other environmental values.

Section 515 requires such analyses only if the clean coal technology project results in an increase in the existing source's "potential to emit" pollution. This phrase is a technical term that would allow actual pollution to increase substantially (in some cases by as much as two or three-fold) from many plants that are operating at low capacity.

There is no need nor any environmental justification for the clean coal technology exemptions in the Administration bill. Clean coal technology projects are being subsidized by American taxpayers because they are promised to be cleaner than conventional energy sources. The clean coal technology projects being funded by DOE should have no difficulty in meeting the most stringent requirements of current law.

Giving such projects the blanket exemptions contained in the Administration bill would encourage sloppiness and invite poor performance rather than superior performance. Such exemptions would also increase local opposition to clean coal technology projects since neighbors would be justifiably suspicious that the exemptions would let the clean coal technology project operate as an egregious polluter.

We support S. 1630's refusal to exempt clean coal technology projects from clean air protection requirements and urge members of this Committee to support the Environment and Public Works Committee on this issue.

Finally, we oppose the provision in the Administration bill that would exempt repowering projects from the cap on SO_2

emissions that applies to other new sources. Section 508 of the Administration bill grants repowering projects all the allowances of the source it replaces and creates bonus allowances for any capacity added by the repowering. This is a "cap-busting" provision that amounts to a back door method of increasing total pollution. It is not necessary because all of the repowering technologies listed in the Administration bill will have emissions that are only a fraction of the allowances of the sources they replace. Thus, even if the repowering results in a significant increase in capacity, there is no need for any increase in total pollution. S. 1630 rejects the Administration's unnecessary allowance for added pollution. We urge members of this Committee to do the same.

The CHAIRMAN. Thank you very much, Mr. Ayres.

Mr. Rosenberg, in the written questions which I gave to you—excuse me, these are answers from DOE. I asked them to provide a detailed analysis of economic energy and environmental benefits of repowering technologies, particularly clean coal. And they point out, among other things, that the advantages are significant. SO_2 reductions up to 99 percent, NO_x reductions up to 95 percent, reduced CO_2 emissions, and various other things, reduced construction costs, et cetera.

Do you concur with those judgments?

Mr. ROSENBERG. I do not have that testimony in front of me. We think they are in that range. If the technologies that they are seeking to promote turn out to be as effective as they hope they will be at this point, of course, we are demonstrating them, and so we do not know for sure but we do know that there is a great deal of progress that can be made, and we think that that really is the answer to many of these conflicting issues that we have had to face in the past.

The CHAIRMAN. Mr. Yamagata testified that there is a $50 billion market in about 2000 or 2005 on clean coal technology. What was the date?

Mr. YAMAGATA. 2000.

The CHAIRMAN. Does that sound about right, or do you have a judgment?

Mr. ROSENBERG. I do not have a judgment on that. We do know that there is a greening of the world in terms of the political activities in other countries beyond the United States. We have delegations coming to EPA every day from all over the world to find out what we are doing. This bill will be a prototype for them to look at.

I do not recall. I think the testimony was that the underdeveloped——

The CHAIRMAN. I think we agree on that point.

Mr. Ayres, do you agree with the central point or points that I just made?

Mr. AYRES. As to the potential export market?

The CHAIRMAN. Well, the potential export market and the desirability of clean coal technologies.

Mr. AYRES. Well, let me start with the export market.

There has been a substantial export market through the 1970s and into the early 1980's for American clean coal technology in the form of scrubber technology, and I think that in the future further technological developments, if they move rapidly, do stand a chance of becoming a major export for us.

I think if you look at the clean coal technology projects, you have to distinguish among them in order to really think about them. The retrofit technologies are the ones which are the most likely to be available in the shortest time span, and for most of this program that we are talking about the obvious solution to the acid rain problem is retrofit technologies, not repowering which requires essentially rebuilding the whole plant. We think it is desirable for those retrofit technologies to go forward quickly, and I think an early deadline is the best way to spur that development.

The CHAIRMAN. The point is that clean coal technologies are desirable and should be pursued for the reasons given.

Mr. Ayres. Yes, but we do not believe that.

The Chairman. I understand your testimony about the date.

Now in DOE's analysis, I asked what year they would be made commercially available, and here is what they say: Pulverized coal with scrubbers, of course, is available now; pressurized fluidized bed, 2005; integrated gas combined cycle, 2005; gas STIGs, 2010; coal-fired turbine, 2010; NHD, 2010; molten carbonated fuel cell, 2010; solid oxide fuel cell, 2025.

Now the earliest of these clean coal technologies would not be available until after the date passes for extension under the bill. So do we not have two ships passing in the night, EPA going in one direction and DOE going in the other direction? If so, would you reconcile the differences?

Mr. Rosenberg. I think that the deadline will establish when they are available to some extent. We are talking about technologies that are 11, 12, 13, or 14 years away, even under our proposal. Those people seeking to develop those technologies now that they know there will be a real market for new technologies will accelerate their development and marketing.

The Chairman. I think we heard that on SDI, too. [Laughter.] Go ahead.

Mr. Rosenberg. We certainly heard that on tailpipes, for example, over the past 20 years, and have seen in fact that technology has developed faster than the auto industry proposed that they would develop it when they were arguing against the bill. So I think there is probably a mixed bag of results.

Some of those technologies are for really new plants rather than retrofit technology. The bill really deals principally with retrofit technologies. Most of the cost of this bill is taking older plants and fixing them up either with cleaner fuels or cleaner coal or cleaner technologies so that they work better.

As far as the next generation goes, the cap has a tremendous impact to accelerate the numbers to the high nineties because to the extent that you have a cap, if you get the newer technologies to work better then the amount you have to make up is lower because you will only have to make up on an offset between zero and a number.

So we think that——

The Chairman. Well, let me ask you this. Excuse me for interrupting.

By the way, I have not said this afternoon how much I appreciate your and Ms. Stuntz's staying here all day. I want to reiterate that. That is above and beyond the call.

How practically can a plant base its whole strategy on buying a technology either for repowering or for a new plant based on a technology that may or may not meet the date? Is that not a problem?

Mr. Rosenberg. Well, it depends upon when you plan to build the plant. If you are planning to build the plant so that it comes on line in, say, the year 2005, those decisions, the final decisions, will probably be made in the late 1990s.

Almost all of the powerplants that have been built are improvements of the powerplants. There is always a sense of technological improvement. If it is really worth a lot of money to the developer, I think the inventors or the technicians, the companies that put together this equipment, will be highly motivated to compete to come up with earlier dates.

The CHAIRMAN. He has to produce the technology and come up with a date, and let us say he makes the date of 2003 instead of 2005. How are companies going to order it in the meantime? I mean, they read DOE, and they say, well, DOE says 2005, and if I rely on that and DOE is right, then I have to drop dead on December 31, 2003. They, therefore, are not going to order it, and thus they are not going to build it.

Mr. ROSENBERG. Well, it is a question of contract negotiation with the supplier as to what extent will the buyer demand a performance by a specific date. That is done all the time in construction projects where the buyer demands that the seller produce something at a specific time or face a penalty in the contract. That will be a spur to the different suppliers to compete to see who can get that technology in place earlier, and in negotiating with buyers that will be one of the incentives the sellers will have.

The CHAIRMAN. Let me ask Ms. Stuntz now, because she is investing $2.5 billion in clean coal technology. I do not know whether you prepared this.

Do you stand behind these dates as the best estimate?

Ms. STUNTZ. Let me point out that in responding to your question here, you asked us for economic, energy and environmental benefits. Coming up with a cost per kilowatt per year is integrally related to the years that we have listed there for commercial availability.

We actually still do think, as Senator Ford said this morning, that we are going to get PFB demonstrated, I think, to commercial satisfaction before the year 2000. We think IGCC is very close behind, but I would say that the costs category there is going to be higher to the extent that we get it on line commercially earlier.

The CHAIRMAN. Commercial demonstration and commercial availability, of course, are two different things.

Senator MCCONNELL. Mr. Chairman, may I ask one question on this point?

The CHAIRMAN. Yes.

Senator MCCONNELL. What is the impact on the environment if we did go from 2003 to 2005? What harm is that?

Mr. ROSENBERG. Well, if you delayed the whole bill for 2 years and that represented all of the benefits, it would be 10 million tons times 2 years. It would probably be less than that. It might be——

Senator MCCONNELL. But if you ended up with tomorrow's technology rather than yesterday's as a result of that?

Mr. ROSENBERG. Well, if that were the choice, I would agree with you, sir. I think, however, that the deadlines that we have selected which we negotiated with DOE when we first put it in the President's bill were an effort to kind of have a balance between the environment and the availability.

Some of those technologies are not for existing plants, but for the existing plants the retrofit technologies would be available and commercially available in time to meet the 2000 deadline; and for the repowering technologies, according to the people who work on this DOE program, it was felt that 3 years would be adequate.

Once we kind of went through that analysis with DOE and mutually agreed that that would be a proper balance between the environment and the availability of those technologies, some of the other——

The CHAIRMAN. Let me ask you this, if I may interrupt.

Mr. Yamagata, you asked for an extension?

Mr. YAMAGATA. Yes, sir.

The CHAIRMAN. Mr. Rosenberg, you say they do not need an extension because the market will respond to the deadline?

Mr. ROSENBERG. I also think that there is another point. When you extend the deadline, you are losing cumulative tons of environmental protection. Simplistically, if it were 10 million tons per year and you extended it for 2 years, the amount of additional sulfur that would go into the air and into people's lungs would be another 20 million tons.

The CHAIRMAN. But you may well be losing the best technology by requiring them to do something else to meet the date, because as DOE says here it has advantages in SO_2, NO_x and CO_2.

Mr. Yamagata, I will ask you and then I want to hear from Mr. Ayres. Suppose we kept that date, the 2003 date, but said something to the effect that provided only if it is not commercially available by a certain date that they will get an extension and not beyond another certain date within which to comply. Would that solve the problem?

Mr. YAMAGATA. I think what you would end up with, Senator, is that reasonable people will differ on when they are commercially available. You just heard several different opinions, for example, on when some of the more efficient though more complex repowering technologies will be commercially available.

I would like to stop right there and remind the committee, as you already well know, the type of industry with which we are dealing here. We are dealing with a utility industry where reliability and the obligation to serve are paramount. That means that if a technology is simply commercially available—that is, that a manufacturer would be willing to guarantee its operability—it does not, therefore, follow that the utility industry will integrate and utilize that technology on all units across their entire system.

I would agree with DOE and Mr. Ayres that the technologies that we look at in which we are most interested with respect to clean coal will be commercially available during the mid and late 1990's. However, not all of the utility systems are going to utilize those technologies just because they are commercially available. They have to be made available for confident commercial use.

That means, I think, that these technologies would be applied across a wide variety of applications through a number of different vendors. So there is that reliability factor established with respect to that technology. That takes time.

So even if these technologies are commercially available in the mid 1990s, we believe that you are going to have to have 5, maybe 10 years beyond that period of time——

The CHAIRMAN. I understand your point. Let me interrupt and ask Mr. Ayres why he disagrees with Mr. Yamagata.

Mr. AYRES. I think you have to think of clean coal technology as being in three categories: retrofit suitable; repowering suitable; and new plant suitable. The development lines tend to be in that order retrofit soonest; repowering in the middle; and new plants later.

The bulk of the acid rain control problem at this point is a problem of controlling uncontrolled emissions from plants which have many years of life left in them. So those are plants where retrofits make sense. You are not going to scrap a 15-year-old boiler and replace it with any kind of clean coal technology. It does not make economic sense.

So the technologies that are most needed are the ones that will be available soonest. The others will not be needed as soon and probably will not contribute very much to the initial acid rain reductions. So the timetable for them is somewhat less crucial. I think that is especially true with respect to clean coal technologies for new plants because, after all, they are going to come on line later after the initial reductions are made.

The CHAIRMAN. Mr. Yamagata?

Mr. YAMAGATA. I would just make a couple of observations, if I may.

Mr. Ayres indicated earlier that an objection they have to the repowering technologies is with respect to an additional extension of time from 2000 to 2003. I guess the suggestion was that you ought to repay those emissions.

I think it ought to be noted that you would in fact repay those emissions if you can commercialize technologies that are more efficient. In other words, if we have a new clean coal technology that will get you 98 percent removal efficiency over the life of that technology, you are going to remove a lot more emissions than if you were to use a conventional technology that might get you 90 percent removal efficiency.

I think I can agree with the point that some of the retrofit technologies are likely to be ready sooner than the repowering technologies. I would go back to the point that I made at the outset, however, that utility managers will use what they are comfortable with and what is reliable.

I would suggest to you respectfully that these technologies are not going to be ready in 1990, for example, when you would have to start making decisions about how you are going to comply with the Phase I part of the program.

Mr. Ayres makes a point, I would suppose, that you could then use those technologies by the year 2000. It goes back to this point about it being market driven. I think you have to remember that at least with respect to the DOE clean coal program, that program is premised on a 50/50 cost-sharing from industry.

A problem that we have right now is that if you drive the regulatory emission reduction program the way it is being driven now, it is unlikely, it seems to me, that the utility industry for one is going to have the financial resources to go ahead and do even the demonstrations of those clean coal technologies. So it seems to me there is at least some question as to whether or not those technologies are going to be commercially available unless we provide the clean coal program with the incentives that Mr. Webb and I both outlined in our testimonies.

The CHAIRMAN. Before I give up my time, Governor Sinner, did you want to contribute on this?

Governor SINNER. Well, one of the driving concerns for my support for Mr. Yamagata's position here is that I do not think we comprehend the fragility of this society faced with energy shortage.

A number of years ago Dr. Lester Brown of World Watch made the point that if we get into food shortage worldwide it will be the developed countries, not the underdeveloped countries, that will suffer. He specifically singled out the United States society because we are so utterly dependent on a source of food other than our own.

I think you can transpose that argument to this issue with energy. Can you envision what would happen if we run short of electricity in a city that cannot refrigerate its food, that cannot run its furnaces?

The CHAIRMAN. Lightning struck my home not too long ago, and I know what you mean.

Governor SINNER. God knows we all want a clean environment. There is a tradeoff here that is very hazardous for this society.

Just as an example, the Missouri reservoirs which generate a good deal of hydropower have been drawn down now in just two years of drought to the point that they no longer can generate full hydropower. They have lost their capacity, and the weather forecast is not very good, frankly, that we will get enough rain to restore that.

Our state has demonstrated its concern for the environment, and I share the wishes of the people who want to clean up the environment. We have to look at the tradeoffs and look at how terribly fragile is this society were it faced with electricity shortage. That, combined with my belief that we have to start conservation measures—that the conservationists are absolutely right.

We also have to be very frank with ourselves and admit that coal is going to be in this picture and has to be in there through this period of cleanup.

The CHAIRMAN. Let me just observe I think there is a solution to this dilemma out there somewhere that I have not thought of yet, and I hope we can think of it. It ought to be the environmentalists and everybody ought to be in favor of clean coal technology, and it ought to be encouraged and certainly from the standpoint of balancing the regional interests. It is clearly something we can do consistent with clean air to help places like Appalachia.

We ought to try to do it, and I hope, Mr. Ayres, you and others will work with this committee and with the clean coal group to try to find a workable way to bring that technology on, to be sure, as quickly as we can, but yet to not snuff out the baby in the crib and prevent, you know, by looking forward and by expecting the impossible to just make it impossible for this to grow.

Let me turn it over to Senator McConnell because I do not want to monopolize the time. He did not get a round this morning.

Senator MCCONNELL. Thank you, Mr. Chairman. Having sat here since 10:15, I am sort of at the bottom of my list of questions, but let me pick up on what the Chairman has just said to the extent that either of these bills are either on purpose or by inadvertence mandated scrubber bills, then we will never get to clean coal technology. And if we make that mistake in our zest to get this job done tomorrow, then we are never going to get there.

I cannot imagine any plant going out and reinvesting all over again after having undergone a massive expense of scrubbing in the nineties with regard to Chris Farrand's observation about as a result of choosing the years 1985 to 1987, the real standard is .9. Only 1 percent of my state's coal can meet that standard.

Now, most of the general questions have been covered. I want to get down to a very parochial concern, and that is the uranium enrichment plant at Paducah, and I guess I will address this to Ms. Stuntz.

Electricity costs account for over 70 percent of the cost of enriching uranium at the Paducah facility. Currently all of Paducah's electricity needs are supplied by one company. Fifty percent of the power that company sells to the uranium enrichment plant there in Paducah is generated at the Joppa plant in Illinois. Fifty percent of that power is purchased by that company on the interchange.

Given that the possibility exists that utilities will be reluctant—and we have heard testimony all day on this—reluctant to sell power on the interchange, has DOE projected what the availability of interchange power will be for Paducah's plant under either S. 1630 or the Bush bill?

Ms. STUNTZ. Senator, we believe there will be adequate power available. We do not anticipate any increase in demand for that plant for reasons you well understand, and we do not believe this bill would have an effect on the reliability or availability of power.

Senator MCCONNELL. Well, moving past the reliability question, have you projected the cost increase if this occurs?

Ms. STUNTZ. We have, sir, although for reasons that Mr. Farrand discussed—and I agree wholeheartedly with him—these things are very sensitive to assumptions, particularly about the success of the trading system, but we believe that it will be somewhere in the nature of 10 to 20 percent on that particular interchange.

Senator MCCONNELL. And then what would be the effect of the price per SWU on uranium?

Ms. STUNTZ. About $15 to $20 per SWU. Let me add that these numbers are based upon our understanding that the Joppa plant will not need to apply a scrubber, that it can even meet the phase II standard by using low sulphur coal but, at that point, we think there may not be effectively that much difference between the cost for the volumes of low sulphur coal that would be required and some kind of scrubbing technology.

Senator MCCONNELL. Given the fact that our percentage of the world uranium enrichment market has already declined precipitously, what kind of impact would this, what did you say, 10 to 15 percent increase in cost per SWU have on our competitiveness?

Ms. STUNTZ. Well, sir, as you know, we are not competitive with Soviet Union enriched uranium right now, and it certainly is not going to help matters any.

I think one thing that would help is if we could get the House of Representatives to see the wisdom of the Senate and pass a bill to help us come up with a privatized operation that could, perhaps, operate more efficiently. But there is no getting around it, this is going to make things more difficult, and it is one of the burdens that we, as the Department of Energy and as a consumer of coal-generated electricity, have got to bear.

Senator McConnell. Cutting right to the heart of it under either of these bills, we are likely to see if there are no changes made, even less percentage of the uranium enrichment business coming to this country, and we will lose that to the Soviet Union. Is that essentially what is going to happen?

Ms. Stuntz. I think it is possible unless we can move forward with some of the restructuring initiatives that we have discussed.

Senator McConnell. Obviously your department believes a viable uranium enrichment industry is in our national interest. You have just alluded to that. The time and the money being spent, for example, to develop and deploy ATWS technology is evidence of that. In fact, in its January 1990 report on ATWS your department said, and I quote,

> Uranium enrichment is crucial to the nation's security. Much of our national defense depends upon enriched uranium including 40 percent of the navy's active combat fleet that is nuclear powered. Uranium enrichment is also an essential part of a full range of fuel cycle services the United States applies to domestic and foreign utilities enabling our country to preserve its leadership role in the nuclear industry.

The report also notes that in the future a health uranium enrichment industry will contribute to the energy security of our nation by safeguarding domestic utilities from nuclearfuel shortages created by supply interruptions and will contribute to the U.S. balance of payments by increasing the foreign purchase of uranium enrichment services.

It is also clear that this committee, the Senate and Congress as a whole, recognize the importance of a healthy uranium enrichment industry as evidenced by the passage of the bill that you already mentioned to try to restructure the industry. Given the previously recognized importance of uranium enrichment industry to the interests of the country and given the fact that the industry as we all just discussed is already struggling, do you really think it is wise to further increase the cost of electricity to this facility?

Ms. Stuntz. Sir, I think just as we have been discussing all day, it is a question of balancing objectives and interests. One of the reasons those facilities are as affected by this legislation as they are is that they have had dedicated to them substantial supplies of very cheap, old, mostly depreciated power plant electricity. And if we are going to clean up the air, which the President clearly has said we are going to do, we need to make an investment in that.

Now, whether we as government or DOE need to absorb some of this cost so that it is not reflected in the selling price in order to keep the product competitive, that may be something we have to face. But I think it would be inappropriate, I believe, to exempt the Department of Energy's facilities from the obligation and the responsibility to help clean up the air.

Senator McConnell. And, of course, what we are all weighing here is just how much we are going to give up for this. Is it going to be—we are going to be out of the uranium enrichment business?

Ms. Stuntz. If AVLIS proves as successful as promised, then perhaps it is sort of an analog to clean coal technology. We may have a technological answer that will make the process so much more efficient that we can get around this barrier. But I cannot say, as you well know, I cannot say that for sure right now.

Senator McConnell. Well, it seems to me the problem is how do we get from today, 1990, to the time adequate clean coal technology can be commercially available without eliminating our competitiveness in the uranium enrichment field and giving up as the UMW claims 30,000 to 40,000 coal jobs at what price, and then Mr. Dowd said this morning the difference between—and no one ever answered—he asked someone—but the difference in an environment between an 8-million-ton reduction and 10-million-ton reduction, at what price do you get the 2 additional million?

The Chairman. If the Senator will yield, I think the problem here is who pays it? If you try to get that from revenues on uranium enrichment, you can't do it. There are already what, 30 to 40 percent above the world market, and so you cannot add those revenues on it without exporting the jobs. Then you do not get it cleaned up, and you lose the jobs both.

Senator McConnell. Well, thank you, Mr. Chairman. Everything else I had has been covered in some way or another.

The Chairman. Thank you very much, Senator McConnell.

Senator Conrad.

Senator Conrad. Thank you, Mr. Chairman.

First, I wanted to turn to Mr. Farrand. You know, I represent one of the states that is a clean state, and you came down pretty hard on the clean state provisions.

I would just like to make an observation that perhaps you are not the most objective observer because I presume that Peabody has operations in Wyoming, and I would presume that those operations might have a change to pick up a pretty attractive market if the clean state provision were present.

Mr. Farrand. Excuse me, Senator, for interrupting. I checked the figures and you would qualify even if you included the industrial emissions of your state, so you are clean from that criticism.

Senator Conrad. I would accept that, and I think that is exactly correct. I mean, we are the lowest state in the nation in other industrial emissions, but your criticism really went to other areas as well. And I do not impugn anyone's motives, but I do think if we are talking about where people are coming from, clearly Peabody would stand to benefit by selling Wyoming coal into North Dakota to replace North Dakota coal.

Mr. Farrand. We also own reserves in North Dakota, and so we have an interest there as well.

My criticism of the clean state provision was on—not with respect to any given state that might be eligible for it, but on the philosophical criteria used to determine whether you are clean or not.

Clean should relate to the amount of sulphur produced into to rather than the amount of sulphur produced from aspecific type of source and secondly, it would seem to us to not matter whether the cleanliness resulted from the application of technology or the type of fuel used as long as it met the criteria otherwise.

Senator Conrad. Well, I would just again say that the philosophical position may flow from the economic position. I do not know that, but I might say to you that I think it is entirely legitimate when you have got a state like ours that is pristine. I mean, you come and see North Dakota. The air is as clean and sweet as it can be.

And we have had an enormous expenditure to keep it that way, and now we see a bill running through here on a very fast track, lots of people jumping on board that says well, that is fine, but now everybody starts from the same point, even those that are out in the east that have not done a thing and our friends in Canada that are right to the north who have not done a single thing to clean up are pouring their product into our state.

And, I mean, at some point it gets old taking economic hit after economic hit, and that is the history of my state in the last 10 years. We have taken all we can take.

Mr. **Farrand**. Senator, if you will recall from my statement, my objection diminishes or goes away entirely if you create a criteria for clean states that is both prospective and retroactive—in other words, that gives states an opportunity as an incentive to arrive at a point by means other than those specifically prescribed in the bill.

The fact that your state was selected because at a certain point in time it was in a certain situation with respect to its emissions and is, therefore, exempted henceforth is not fair to a state that might sometime between now and 2000 attain the same kind of emission achievements and not be eligible.

Senator **Conrad**. Let me just ask the Governor if he would like to respond to that because he is running a state that has an awful lot to lose after doing an awfully good job of cleaning up and being clean and having a sincere environmental concern.

Governor Skinner. Senator, thank you. I do not disagree, Chris. We did not really draft this bill. We had to work within the framework of the bill.

I think if you looked at the numbers you would find that there are only three states have less SO_2 emissions per square mile than our state, and frankly, the genesis of this bill is hard for me to understand because how you can identify our state as being forced to do a lot more cleanup while states that have huge populations suffering from sulphur emissions three, four or five times what ours does do not have to really, and that is not on the table. The industriale missions are not on the table.

It is hard for me to understand, and so we are not suggesting that this is the perfect bill. We are just saying that from our point of view it is patently unfair since there are only three states that have less emissions than we do, and we care about that.

Somebody said well, you have got all these people that you have to think about, but the fact is that is precisely the point. You have all those people that have to breathe the air, and yet many of those states that have no electrical generation and have all these other industrial emissions, they are not even in the loop.

And so we do not argue with your point. It is just that we have to live in the real world in this bill.

Senator **Conrad**. I do think—you know, we find ourselves in a very difficult position because of the structure of the bill itself, and I really do wonder how we go to people and say that this structure itself is fair, just the basic structure.

I understand that in response to a whole set of political pressures——

Mr. **Farrand**. If I understand it, Senator, the designation as a clean state does not exempt you from the post-2000 offset requirement for new facilities.

Senator **Conrad**. That is exactly right. I appreciate that comment because I think there has been some confusion about that. People think we are exempt forevermore. That is just not the case, and it is also not the case, very frankly, in our state that this means there are not going to be more emissions than there already are.

I read the news media back home. Well, we are going to have more emissions. Well, that is not the case. I mean, that is not the hard reality.

Mr. Rosenberg.

Mr. **Rosenberg**. We do not accept the Clean States Amendment, but we do like the bonus arrangement. And really what that does, is that for a state that has plants that are emitting at high levels, they must pay a significant price to reduce those levels to the 1.2 rate. If they want to grow beyond that, they have to make up additional growth allowances at an economic cost.

The way the Senate Bill came out without the Clean States Amendment to it, the clean states do not have to reduce their emissions as the dirty utility plants do, and they get a 20-percent bonus to cover growth. There was an attempt to recognize, by providing that 20-percent bonus, a growth factor, so that in a dirty state—I hate to use these words, but a state that has a lot of SO_2 emissions, to get growth, there has to be not only control down to 1.2 but over-control.

But in a state like North Dakota, you would not have to control the existing plants anymore, and there would be 20-percent bonus in allowances for those facilities.

Senator **Conrad**. Does that apply to all plants in the state?

Mr. **Rosenberg**. That would apply to all plants that are under 1.2, I believe.

Senator **Conrad**. There is the difference, because here you have got a situation in which you may have three plants, two of them owned by the same power company and they are exceptionally clean. And they have got an earlier plant that has a higher level of emissions that was not even operating in 1985 because of a surplus power situation, and yet our total rate of emissions is very low. And we go out and hammer that plant. I mean, frankly, I just cannot see the justification for it.

Mr. **Farrand**. We run the risk here of sort of mixing apples and oranges, it seems to me, because the Clean State Provision may have got ten clean largely because they had plants under 1.2 in 1985, but in fact the problem with plants in that so-called class of 1985 is a different problem. Your plant may have been a very clean plant, but happened not to have been operating very much in 1985. It does not benefit very much by the 20-percent potential bump or bonus it gets.

In that sense, the administration's bill is much better for you than what is in the bill.

Senator **Conrad**. Thank you for that, by the way. That is exactly the situation that we face, and frankly, under either of these provisions you still have that problem if you have plants that were not operating because of a surplus power.

If you look at North Dakota's economy, the energy economy had gone on the dumper, the agricultural economy had gone on the dumper, and so some of our plants were idle.

Let me just ask very quickly, Mr. Rosenberg, system wide average at 1.2 or 1.1, what would the tonnage be under that scenario? We talked about this earlier.

Mr. ROSENBERG. Without the cap, there would be a loss of between 1 million and 2 million tons from 2010 to 2020, depending upon the growth scenario. That is what we showed in one of our charts. So at a 1.2 rate, if you in fact——

Senator CONRAD. So we would be talking a savings of 8 to 9 million over 1980?

Mr. ROSENBERG. 9 million under 1980 is the target number. 8.9 million.

Senator CONRAD. That is on a statewide average basis. What would happen on a systemwide average basis? A reduction to 1.2 or 1.1, what would that do to tonnages?

Mr. ROSENBERG. I gave it to you on a national basis. If all you had was a rate bill at 1.2, we would estimate that there would be an erosion of 1 to 2 million tons out of the 9—out of the 10-million-ton reduction. I do not have it broken down by systems, per se. But if it was all the systems, and it should not make much of a difference on an average, so you are still talking about the same loss of 1 to 2 million tons.

Mr. AYRES. Senator Conrad.

Senator CONRAD. Yes, sir?

Mr. AYRES. It seems to me, though, there is no real argument for changing to that kind of system except if you happen to want to make the program less restrictive, because the trading system provides for the flexibility that is argued for as the basis of statewide averaging or system wide averaging, or whatever it is. So I think the right place to look is where you were asking. what does this cost in environmental terms. I think in our view, also, the cost is too high in environmental terms, and it does not do a thing for flexibility.

Senator CONRAD. What if we were on a plant—well, Chris, did you want to comment?

Mr. FARRAND. Well, I would just disagree with the flexibility factor. I think even the EPA's estimate of the incremental cost of having the cap or not having the cap and at least using a 1.2 pound statewide average was an incremental $2 billion a year. The question is, Does that extra $2 billion a year buy you commensurate benefits in terms of changes in deposition?

Mr. ROSENBERG. We estimate actually $1 billion per year, but we think that is 25 percent of the cost of the bill, and we thought that would be a—that is a significant difference, to be able to reduce, I think the cost of an expensive bill by 20 percent was the reason to do it.

And I think there is a very strong sense this is not simply EPA, but the White House in wanting to have a properly accountable emissions trading system as a demonstration on how to make that work and as a demonstration on how to develop methodologies in other pollution programs that could also reduce these burgeoning environmental costs to the society.

And so it is very important to be able to demonstrate in this area where we believe we can have an accountable and effective program that we can reduce costs 20 percent when costs are going up so dramatically.

Senator **Conrad**. Does anybody else want to comment on that?

Ms. **Stuntz**. The only comment I would make, sir, and I believe you are up on this from your questions earlier, concerning the NO_x Provisions in the Senate bill, we have a disagreement with EPA about the effect of those. We never had those disagreements, of course.

But we think it is somewhat more significant than they do, and since there is interpollutant trading, it could, in fact, end up that you cannot get to the NO_x level that S.1630 would require you to do so that you wind up doing more SO_2 reductions. We think that could actually make the SO_2 reduction requirement even more severe with very little environmental benefit to pay for it.

Senator **Conrad**. I hope that point is starting to emerge in a way that my colleagues have fastened on it, because our own analysis would lead us to that conclusion. I hope the point is being heard.

Governor Sinner. There may be a possibility to address both the need for a reliable supply and this question of history by changing the one provision that says that the SO_2 determination would be based on 1985 or 1986, which is what some states want, and others want later date, as we do.

You might be able to say—the language might be able to say the highest 2 years of production during the timeframe 1985 through 1998 so that you would take a real look at what was needed in a society that is kind of volatile with global marketing and those kind of things, and take into account these various components of the situation.

Senator **Conrad**. You know, we have got a situation, and I am going to end here, Mr. Chairman, but I do want this final point to try to get Mr. Rosenberg perhaps to help us think through how we might accomplish what seems to me to be a reasonable thing to attempt to accomplish. And that is, Arkansas sits here with a very real problem.

Senator Bumpers outlines a problem that is very real. They are down there at .4 on two plants that are 800 megawatt plants during that time period, and now those plants are operating at .7, and they are going to get hammered. We have got a situation that is not identical, but very close to that.

There has got to be some reasonable, rational, fair way that we can take note of these kinds of differences, so that places do not get hammered because of inadvertence. I mean, it cannot be our intention through governmental policy to go out and slam people that have made big expenditures, done a good job, are clean states; and we go out and nail them because the 2-year time period, they were at low levels. Do you have a suggestion for us?

Mr. **Rosenberg**. Well, Senator, there really were two on the table. And one was in the administration's original bill, where your particular problem apparently would be resolved, according to Chris, which said that if someone had a clean plant that was operating below 1.2 and that plant was operating in 1985, there would be no restrictions on how much that plant could operate, as long as they maintained the rate of whatever it was. And then in the Committee debate, that was viewed as one problem. And another problem——

Senator CONRAD. Wait, let us not lose that thought, though. That, as I understand it, does not solve the problem. I mean as long as you stay at that rate, that is a state that is not sustainable. Arkansas is at .4. They are now at .7, and you would say as long as you stay at .4.

Mr. FARRAND. That might solve your problem, Senator, because most of your capacity is scrubbed. That does not solve Arkansas' problem.

Mr. ROSENBERG. What happened was that the committee looking at the same set of problems on the clean states decided it was too hard to figure out a solution, so they gave everyone a 20 percent bonus. And it was not that people were not trying to figure it out.

And there were really two ways of approaching it. In both cases you get the overall reductions that seemed environmentally sound, the 10 million ton reduction, but the committee did wrestle with this issue and decided the way they could approach most states on this issue is if you are a clean plant and you are operating, there is a base formula. And if you are a clean plant and you were operating below 1.2, you get a 20 percent bonus based upon your 1985 levels as a way of being equitable.

Mr. FARRAND. That also does not solve Senator Bumpers' problem.

I might add that people who have looked at this problem, the so-called class of 1985, have made a recommendation to the other committee, and if you will indulge me, it is a very quick recommendation. It is that the operator be given the option of either selecting 120 percent of his baseline tonnage emissions, which is what the committee bill now says, or what EPA originally proposed which is that you assume a 65 percent capacity factor in 1985 as an option.

The third option is that the operator can elect to meet either the lesser of a 1 pound standard or what ever the limit is, if it happens to be lower.

Mr. ROSENBERG. And the only problem with that is that we have to determine whether if you gave all of those three choices to an operator and each one optimized their choice, would we lose the environmental benefits we are trying to achieve, which is a 10 million ton reduction, because it is sort of a zero-sum game. And every time we have gotten into those analyses, we have always found that you end up losing a half a million tons or a million tons.

Mr. FARRAND. My understanding is the estimate of the tonnage difference would be 120 to 150,000 tons.

Senator CONRAD. You know, this really gets right down to the nub, though. I have to say to you, maybe we have got to open up our minds collectively and conclude, in order to treat people fairly and get some medicine that will go down, we give up 150,000 tons somewhere.

I mean, you know, where do we get this magic number of 10 million? Hell, nobody can tell you there really is 10 million, anyway, and we get 10 million and that becomes the Holy Grail. Willy-nilly, fairness, willy-nilly whether or not it makes any economic sense. But it is a number that has got a ring to it, apparently because it has got a lot of zeroes.

Mr. ROSENBERG. Well, it is the number that we have been given to work with by the President.

Senator CONRAD. Where did he get that from, do you know? Did he go to the mountaintop?

Mr. ROSENBERG. I think what we can do, Senator, is study this proposal that Chris mentioned. We will do an analysis on it and see what it comes out.

Senator CONRAD. I would appreciate that.

Mr. ROSENBERG. When we have done similar types of analyses, we have come up short, but we will look at this one as well.

Senator CONRAD. Maybe this time, for a re-estimate.

Mr. FARRAND. Sort of like the budget process, do you mean?

Senator CONRAD. Thank you, Mr. Chairman.

Senator MCCLURE. If I could just very briefly ask a question. I will not take very long. I think Senator Heflin has comeback, and he has some questions he did not get a chance to ask this morning. I do not mean to burden the time that he would have, but there are two or three things that I would like.

As I understand, Mr. Rosenberg, you said earlier today, that you have done a state-by-state analysis of the effect on electricity rates.

Mr. ROSENBERG. Yes, we have.

Senator MCCLURE. Can you make that available to the Committee, please?

Mr. ROSENBERG. Certainly.

Senator MCCLURE. And that you have also done a cost estimate of the Senate bill as contrasted to the administration's proposal?

Mr. ROSENBERG. And I believe that it is being circulated today or tomorrow.

Senator MCCLURE. And is that also state by state?

Mr. ROSENBERG. Not the draft that we have tomorrow, but we are doing a total analysis of the Senate bill with our computer models, and they will be available early next week to the Senate as well, state by state.

Senator MCCLURE. You said you had discussed a package of amendments?

Mr. ROSENBERG. We said we had a whole series of hearings, dozens of them, where we talked about the Administration's bill which had been introduced by Senator Chafee, and the Committee draft, we have not yet prepared any specific package of amendments.

Senator MCCLURE. You have no package of amendments to the Environment and Public Works Committee?

Mr. ROSENBERG. That is being prepared right now.

Senator MCCLURE. When will that be available?

Mr. ROSENBERG. I hope sometime next week as well.

Senator MCCLURE. I want to share the comments that were made earlier. I do not know where 10 million tons came from. I suspect I know, after years of discussions that this has been going on for. I think it was before the Environment and Public Works Committee for nine years. Maybe we should have said 9 million tons, one for each year. That might have as much rationale as any other.

But I suspect what happened is people discussing the problem, looking at the tradeoffs, came to kind of a consensus that hey, that is about what the system will stand—somehow a tradeoff between the economics and the environmental benefits, and that is the tolerance level between the people on both sides, that said that came close to the meeting of the minds.

Mr. ROSENBERG. I think that the genesis came from a National Academy of Sciences study that recommended about a 50 percent reduction, and at one point it was estimated that the original levels of pollution in 1980 were around 22 to 24 million, and that 50 percent evolved into a 10-million-ton program.

Senator MCCLURE. Well, why was it 50 percent instead of 40 percent, or 60 percent?

Mr. ROSENBERG. I do not know why the scientists recommended that, but that was the genesis for the discussion.

Mr. AYRES. If I could comment on that, I think Mr. Rosenberg is right in pointing to those studies as the genesis.

Senator MCCLURE. Then that is even more arbitrary than I had suspected.

Mr. AYRES. Well, the studies have all basically tried to assess what reduction was necessary in order to protect the environmental values.

Senator MCCLURE. What reduction is necessary?

Mr. AYRES. The Academy essentially said a halving of the 1980 levels of emissions, which is why we have argued for sometime for a 12-million-ton reduction and regard 10 million tons as a reasonable compromise.

Senator MCCLURE. Why did you say 12 instead of 14?

Mr. AYRES. Because that is half of what the 1980 emissions were.

Senator MCCLURE. Again, what is the magic in half? Would not 14 be better?

Mr. AYRES. The genesis of halving was from the National Academy of Sciences, who estimated that cutting emissions in half was about what you needed to protect the sensitive environmental values that were at stake.

Senator MCCLURE. Now, would not reduction of 14 million tons be better than reducing 10 million tons?

Mr. AYRES. It might be, but cutting the emissions in half has the support of the National Academy.

Senator MCCLURE. It has support. It is totally arbitrary.

Mr. AYRES. I think I might disagree with you there.

Senator MCCLURE. All right. Tell me what was the basis?

Mr. AYRES. The basis of it I assume was that the scientists who wrote the Academy's report had examined the science underlying this issue and come to that conclusion. I mean, this is a scientifically derived target, is what I am saying; 10 million tons is a sort of compromise on the scientific——

Senator MCCLURE. I understand. All I am trying to say is that there is no magic to 10 million, as to whether it is 9 million, or 11 million, or 8 million, or 12 million. There are tradeoffs, economic and environmental, and the other factors are tradeoffs from those points.

Mr. Farrand?

Mr. **Farrand**. Can I make an editorial comment on that? I think that at least with my company, and I think with large segments of our industry, there was acquiescence to, if not the reasonableness, the probability of the 10-million-ton reduction, and we were all basing our planning accordingly.

What is different about this proposal, however, is the cap, and if you measure the effect on existing facilities, including the offsets required to meet new growth, the effect on existing facilities is far beyond what the effect of a 10 million ton flat reduction would be, and so this is more than what had been in the common vernacular all these years, in my estimation.

Senator **McClure**. Well, again, I do not know that there are any scientific boundaries that absolutely bound our discussion we are making tradeoffs here—if I understand the Administration's position, Mr. Rosenberg or Secretary Stuntz, the Administration's position is that the Senate bill, costing several multiples of the Administration's bill, gains about a 2-percent benefit in emissions reduction, is that correct?

Mr. **Rosenberg**. Not on the acid rain issue.

Senator **McClure**. I understand that. For the bill overall. But if I understand the acid rain provision there is about a $400 million difference between $4 billion $100 million and $4 billion $500 million on the acid rain provisions of the two bills, is that correct?

Mr. **Rosenberg**. Right. There is a 10-percent increase in acid rain and about 100 percent increase in the bill as a whole.

Senator **McClure**. That is a per-year cost difference, that is not a cumulative cost. That is every year.

Mr. **Rosenberg**. Right.

Senator **McClure**. One question that I hope to get some comment on, I am struggling with exactly how the Administration fixed on your time schedule and how you view the time schedule as in the EPW bill with respect to the tradeoff between using retrofit technology and extending the life of old plants as contrasted with the desirability of getting old plants shut down and new plants on line.

Now, there are other advantages to new plants that are just better emissions control, are there not? They are more efficient, presumably. In an energy sense more efficient and in an economic sense more efficient, is that not correct?

Mr. **Rosenberg**. Yes, sir.

Senator **McClure**. So as a matter of public policy we would like to get old plants removed from the inventory and substituted by new plants that have all of the range of benefits, not just a reduction of emissions, and we have to make a tradeoff here between retrofit requirements—if we retrofit them all right now and extend them a little bit we will slow down the process of replacement, is that not correct? Is there any disagreement with that?

[No response.]

Senator **McClure**. As we extend the life of marginal plants into the future further we reduce the advantages of getting new plants on line. Is that not correct? Is there any disagreement on that?

[No response.]

Senator McClure. All right, if I can take it—and I am not trying to trap anybody here, I just want to know how in the world did we decide that this amount of time lag, or time allowance, is the best way to get the best possible mix of allowing people the time to develop and apply and put into effect new technologies, rather than retrofitting old plants that make that less possible? Mr. Rosenberg?

Mr. Rosenberg. Well, one of the reasons we favor a 107-plant versus a 20-plant option is to essentially rachet down in two steps that enable fuel changes and minor technology changes to be made in the short term to achieve a rate of 2½, which can be achieved in many, many ways, to allow a more full implementation of the better technologies in the second phase.

So the Administration was very strong on not having a scrubber mandate bill in Phase I which would preclude better technologies than are being developed under the clean coal program toward the end of the decade. So we wanted to get the reductions as soon as possible.

We found that there were very many, very cost-effective reductions that could be made at a 2½ ton rate, or 2½ pound rate, either through improved efficiencies or better fuels, and still only incur 10 percent of the cost of the program in 1995. I get half of the environmental advantages earlier, but give enough time for an orderly implementation at the end of the decade for the bulk of the expense and the other half of the benefits.

Then we were educated by the Department of Energy that there were other technologies generally known as repowering that need a little bit more time, and we conceded those additional years.

So there was a very careful view of how do we get a balance between as much environmental benefits as possible in the short term, but not do it in a way that is disruptive and that does get us benefits over the long term that take advantage of the new technologies and advantage of the cleaner fuels in an orderly way.

It was sort of a real careful discussion between the Department of Interior and the Department of Energy, EPA and the White House to kind of work at that, and then we had to defend that before the Committee and they basically, coming at it from their perspective, agreed.

So this is one of the areas where there has been a unique amount of agreement within the Administration and between the Administration and the Committee.

Senator McClure. Mr. Ayers?

Mr. Ayres. I think that it may be a little too simplistic to think of it just in terms of a desire to get new technologies for some plants, and I would say it was probably the bulk of the plants that caused the problem now.

It would be uneconomic to think in terms of scrapping them, or scrapping the boilers at those plants at this point. They may be 10, 15, 20 years old, and for those plants the economically sensible thing to do is retrofit.

So I think in general I would agree that improved technology is something we should be looking for, but I think when you look at the universe of plants that we are dealing with here you find that that is only a generality, and in many cases what you are looking for is a retrofit.

Senator McCLURE. One of the difficulties is that generalities prove wrong, whether it is desirability or lack of desirability, they are not all 10, 15, or 20 years old. They may be 25 or 30 years old, or 35 years old, and what is the right answer there? Retrofit and extend them for another 20, or get them out of the inventory and replaced, and that has got to be almost a plant-by-plant decision, it seems to me, rather than the generality that policy generally expresses in statute.

Ms. STUNTZ. Senator, if there is a generality—and I would concur with Mr. Rosenberg's description of what really was a painstaking process in terms of trying to evaluate where are these technologies, where will they be, how much can they contribute not just in acid gas control but in efficiency? We have to think about things now like global climate change. What is the future of coal? How do we have the best future for coal with these other challenges?

But the one generality I would say that came out of that process—and I am sort of surprised by the remarks—is that we do not want to lock in current technology. We do not want to have the retrofits that are on the shelf now that produce sludge, that decrease efficiency, that do not have the kind of promise that we have talked about with some of these repowering technologies.

We wanted to give every incentive we could so that when that capital investment was made which was accurately pointed out earlier, you are only going to have one crack at that, it was made in the technologies that would really help us meet the most objectives in a way that was best for the future of coal.

Senator McCLURE. I understand that is your objective. There are some people who say you have not really reached that objective, even though they understand that is what your objective was.

Mr. Farrand.

Mr. FARRAND. Senator, I would like to get back to the issue of the ripeness of repowering technology, if you will not hold me to the numbers. And I will check them.

I believe that about 46 percent of our existing coal-fire capacity came online in the 1960's and 1970's. That means that by the year 2000 they will be the class that is not ripe for retrofit but is in fact ripe for repowering. If indeed that technology is ready, there will be a huge potential market for that on a larger scale.

I am reminded that the average age of all coal-fire generating capacity by the year 2000 will be around 40 years of age or more. So there is both room for the development of new technology to displace the outmoded existing plant base, but there is also a big market opportunity to repower very large existing units.

Senator McCLURE. I am sure that is true. And I am worried about two aspects of that. One is the expense borne by industry to retrofit, and at the same time to invest in the development of new technologies. Those investments have to occur simultaneously.

Mr. FARRAND. Well, I find myself agreeing with Mr. Rosenberg on the effect of the two choices that the President had, whether it is 107 plants or 20 plants, on this point. Because it will probably be easier for a lot of plants to do things in Phase I that are less capital intensive, and save that capital, in essence, to deal with the Phase II requirements in either repowering or beginning to think about new capacity.

Senator McClure. I understand that. I am concerned, and I will not ask for comments at this time, because it is time that we let some of you go back to work, including myself, I am concerned that there is the overlapping investment requirement, and there are some plants that do not fall neatly into one or the other. The plant operator has to make the judgment, where is that risk?

Now if I were a plant operator, I would really worry about whether that new technology is going to be there in the year 2000, ready for me in 1995 to make the plan to have it online in 2000. I do not think we are at that point yet. And yet they have got to gamble that it will be ready, or they have to put the money into retrofit.

And if they put the money into retrofit, then they have to operate the plant for a longer period of time in order to get their money back, or compound the investment they have to make.

Mr. Yamagata. I would just make the point, Senator, that along with that rationale, those who would argue, as has been done here today, that the deadlines are a market-forcing mechanism, that the obverse may be equally true.

And that is that if we invest in scrubber retrofits, for example, on a plant that is 15 years old, a good utility operator or manager is going to want that powerplant to run for not another 15 years, but another 30 years at a minimum.

And what you are really doing is taking away the demand for the new option itself.

Senator McClure. There ought to be a way, and I would suggest that if you can answer this in writing later, you do so, rather than try to do it here now, for government to share the risk; share the risk in the decision that must be made so that if a plant manager decides, no, I am not going to retrofit, I am going to gamble on the availability of new technology, and gets the approval of the appropriate governmental agencies to go that route, that the government shares the risk as to whether or not that can be done.

Mr. Rosenberg. What we would rather do is create a market opportunity with free competition for the utility manager, who is used to a monopoly, to operate like other business people do, where they take risks.

Senator McClure. Let me put it this way. That is fine unless it is a risk that was created by the Government. But what you have just said to me is, we will create the risk and you poor devils out there take it all.

Now, that I have heard from government far too often. I have had it up to here with government that decides that somebody else should take the risk which government creates and government is not bound by it. Whether that is by state regulatory agencies or by federal agencies.

If government wants to create risks, government ought to share it and not just pass it off and say, now that is your problem, be good competitors. Because how in the world can business compete with government in the creation of risk?

Well, I think there is a better answer than just to say, hey, we are going to create the parameters, now you go out and take your chances. We create it, we should share in it.

If we decide that indeed that utility ought to, having made a decision to bypass retrofit as an option on the reasonable assumption—we share in that decision—on the reasonable assumption that a new technology will be available in a timely and economic way, that government then not be in the position of coming back and say, hey, you guessed wrong, did you not.

Mr. Rosenberg. Senator, are we not sharing in the risks by spending all the money that the government is spending through the Department of Energy's clean coal technology program?

Senator McClure. That is a part of it, but that is a sharing in the expense, but not a sharing in the risk as to whether we will achieve it at a particular time. And we are setting up timetables in this legislation. And the ability to meet those timetables is not wholly within the competence nor the control of the utility that will have to make those decisions.

I think government ought to share in those decisions and share in the risk of whether or not they were right.

Thank you.

I think I was supposed to say when I got through that the committee will now stand in recess until the hour of 9:30 tomorrow morning. Thank you all very much.

[Whereupon, at 4:40 p.m., the hearing was recessed, to reconvene Thursday, January 25, 1990, at 9 a.m.]

ENERGY POLICY IMPLICATIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1989

THURSDAY, JANUARY 25, 1990

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 9:05 a.m. in room SD-106, Dirksen Senate Office Building, Hon. Malcolm Wallop, presiding.

OPENING STATEMENT OF HON. MALCOLM WALLOP, U.S. SENATOR FROM WYOMING

Senator WALLOP. The committee will come to order.

Let me begin by thanking Chairman Johnston for the accommodation of the time requirement of Governor Sullivan.

Let me also begin, Mike, by saying what a tremendous pleasure it is to welcome you here. We are here to receive your testimony on behalf of the Alliance for Acid Rain Control. I think it is more than a little important, and I think it is entirely useful that the Governors have joined together. I will not waste any time on a statement of mine and would welcome yours.

STATEMENT OF HON. MIKE SULLIVAN, GOVERNOR, STATE OF WYOMING, AND COCHAIRMAN, ALLIANCE FOR ACID RAIN CONTROL, ACCOMPANIED BY NED HELM

Governor SULLIVAN. Thank you very much, Senator Wallop. I appreciate the invitation to testify today. I am here, of course, was Governor of Wyoming but as well in my role as Co-Chairman of the Alliance for Acid Rain Control, a bipartisan coalition of 14 current and former Governors from every region of the country but the lower midwest. It has bene actively involved in the acid rain debate since its inception in 1985.

I have submitted written copies of my testimony to the committee, and I am anxious to answer any questions that you or other members of the committee may have today. So I will briefly highlight the Alliance's concerns, commendations and recommendations about the legislation before the Senate.

First, let me share some personal observations on why we feel strongly about the need for acid rain legislation that is there and flexible. I know you have been to Wyoming, and I say this for the other members of the committee who, if they have not been there, I hope they will.

You know that Wyoming has the cleanest air in the Nation because we have some of the toughest air quality standards in the Nation. We have those standards because we made tough decisions years ago that are now being asked of our friends in the Midwest. You may recall, Senator Wallop, as an example, one of my first decisions as Governor in 1987 involved requiring, even though there were environmentally accepted alternatives, Pacific Power & Light, Wyoming's largest utility company, to install a scrubber on one unit at its Jim Bridger power plant at a cost to that company and the consumers served by that company of approximately $80 million. I had to make that decision knowing it could have a potentially adverse economic effect on the consumers of Pacific Power.

That was at a time when Wyoming was in deep economic recession with double digit unemployment in many areas. When we weighed the need for a clean environment against the need for a strong economy, we determined that the health of our citizens and the integrity of our environment should not be compromised for economic reasons.

Now we at least seem ready to deal with the issue of clean air on a national basis, and some are ready to cry foul because we are finally asking them to do what many of us have already done at great cost.

I am here today to commend both President Bush and the Senate Environment Committee for their clean air legislation, which adheres to the simple principle that those who pollute should clean it up. The Alliance urges members of this committee to strongly oppose any attempts to provide new subsidies to help some regions meet their acid rain obligations.

I stress "new" because the legislation before you already contains subsidies for high sulfur midwest coal through a $2.5 billion clean coal technology development program that the Alliance supports and through the allocation of emission allowances that will not assist in any particular way the clean states.

Yet, in the lower midwest states are still pushing for more subsidies. Some high sulfur state Senators are reportedly developing a plan where dirty power plants could double allowances for reducing emissions. Worse still, they reportedly are contemplating greatly reducing the number of plants affected by the first phase of the acid rain bill and extending by two years the time the remaining dirty plants have to install scrubbers.

This attempt to bias the market against low sulfur coal in favor of natural gas in favor of expensive scrubbers to protect high sulfur coal is simply unacceptable in our view.

The Alliance does and has supported some inequity in the emission allowances, but we do ask that the legislation be amended to give clean power plants partial credit for already being below the 1.2 pound emission rate. Cleanup efforts should be rewarded no matter in what region of the country they occur. My written testimony offers several ways this can be accomplished without endangering the 10 million ton emission reduction goal which we support.

This inequity in emissions allocations was recognized by the Senate committee in its approval of the so-called Clean States Amendment to S. 1630. I know that my good friend George Sinner of North Dakota testified yesterday before this committee, strongly supporting the need for this provision. It was thought that this provision would also help Wyoming and other states; however, it does not provide any recognition for our most recent cleanup efforts over the past five years.

I would, therefore, ask and recommend and suggest to the committee to consider an amendment that would allow states to opt out of that Clean States Amendment and be regulated under other provisions of the bill instead to take advantage of the gains that have been made since 1985.

I want to briefly outline two other concerns of the Alliance. First, we support amendments which ensure that selective catalytic reduction is not forced on wall and/or tangential fired boilers. This is simply not a cost effective method to reduce NOx emissions.

Secondly, the Alliance supports legislation for an action to address the problem of visibility in national parks by establishing regional State and Federal commissions to make recommendations to the EPA on which pollutant sources should be controlled and what types of control should be required.

Mr. Chairman, I have tried to be brief. I hope that if there are any additional questions I can respond to them, but I would like to make one final observation. The acid rain debate has become increasingly acrimonious, and it seems to pit one region of the Nation against another. That is unfortunate. This legislation will certainly have a sweeping direct impact on the economy of many states. There will be, as is usually the case, winners and losers.

You know, Senator, I would be less than honest if I did not acknowledge that I hope Wyoming will benefit economically from this legislation. I also hope, however, that we do not lose sight of the fact that this legislation is primarily designed to protect our environment. You do not have to go too far from this room to see the effects of pollution and of acid rain, and it has particular significance in areas of pristine wilderness, areas that you and I are dedicated to.

We must begin to ask ourselves if something is not done now, can it ever be repaired? More delays, inappropriate compromises or loading unnecessary economic cost on our country in exchange for a few jobs is not a fair trade. I saw "few" because there are provisions already to ensure the high sulfur coal industry remains viable.

We asked for fair, flexible legislation. The legislation before you as submitted by the President and the Environment Committee offers the way to begin to address the acid rain problem immediately in the most cost effective manner possible. We think there are some changes that would be fair and equitable to those of us who have undertaken the role to clean up already and have paid for that cleanup. We hope that we will be given some consideration in that regard, and we wish you well in your debates.

[The prepared statement of Governor Sullivan follows:]

Statement of

Governor Mike Sullivan,

Co-Chairman, Alliance for Acid Rain Control

before the

Senate Committee on Energy and Natural Resources

January 25, 1990

Thank you Mr. Chairman for inviting me to appear before you today. I am testifying today on behalf of the Alliance for Acid Rain Control, which Governor Rudy Perpich of Minnesota and I co-chair. The Alliance is a bi-partisan coalition made up of 14 current and former Governors from every region of the country except the lower Midwest, as well as a number of public interest group leaders and representatives of industry and academia.

The Alliance has been very active in the acid rain debate since our inception in 1985. We have testified a number of times before House and Senate committees, although this is our first opportunity to appear before this committee. We also helped draft the Proxmire-Simpson bills of the last two Congresses and worked with the Bush Administration as it crafted its recent Clean Air proposal. The Alliance has a strong and serious interest in the legislation you are considering today. Needless to say, as Governor of the largest coal-producing state in the country -- a state which is spending hundreds of millions of dollars of its own money retrofitting scrubbers on power plants burning low sulfur coal -- I also have a very strong personal interest in this legislation.

I will focus most of my remarks today on several of the key issues in the acid rain debate, although I would also like to comment briefly on policy to address visibility impairment in our national parks.

As you may know, the Alliance has endorsed the President's acid rain proposal (S. 1490). We strongly support the 10 million ton sulfur dioxide emission reduction requirement and the emissions trading scheme designed to minimize the cost of meeting that environmental goal, both of which are cornerstones of the Alliance's policy position. We also applaud the Senate Environment Committee for adhering to these principles in its bill (S. 1630). The Alliance strongly encourages members of this Committee to oppose any attempts to violate the environmental integrity of the 10 million ton reduction or the economic integrity of the emissions trading provisions of the bill.

Acid Rain Clean-Up Subsidies

We also want to encourage members of this Committee to oppose any attempts -- either direct or otherwise -- to provide new subsidies to help the lower Midwest meet its acid rain obligations. I want to stress the adjective "new". Somehow, in the debate over whether Congress should add a national electric tax or a national emissions tax-financed trust fund to help the lower Midwest pay for its clean up, we have lost sight of the fact that the acid rain legislation proposed by the President and the acid rain bill passed by the Senate Environment Committee both already contain subsidies for the Midwest.

The first subsidy is in the form of a $2.5 billion dollar commitment to the federal clean coal technology development program. Make no mistake about it, that is a significant subsidy to the high sulfur coal, lower midwestern states. The second subsidy is inherent in the allocation of emission allowances under both S. 1490 and S. 1630. As the legislation is currently structured, a dirty plant in the lower Midwest is only required to meet an emissions cap based on a 1.2 pound emission rate. If that dirty plant reduces its emissions below the 1.2 standard it frees up emission allowances equal to the difference between its new emission rate and the 1.2 pound rate. Those allowances can be sold to other utilities. In contrast, a clean plant in Wyoming, New Mexico, Louisiana or any other clean state, which has been emitting at a rate well below 1.2 for years, receives no extra emissions allowances for having already done the job of cleaning up. As a result, when it comes time to build a new power plant to meet the demands of economic growth, clean states may not be able to find the emission offsets needed for new plants in their own region and may have to buy emissions allowances from power plants in the lower Midwest. That is an off-budget hidden subsidy.

I want to go on record and say that the Alliance supports the clean coal technology program, even though it is a subsidy to the Midwest. We are also willing to accept some inequity in the emissions cap system in which clean states do not get full credit for past clean up efforts -- I will outline later a proposal we have for giving clean states at least some credit for past clean up efforts. We believe, however, that these concessions to the Midwest are generous enough. We do not want to see any new subsidies.

I want to outline a couple of basic reasons for opposing subsidies to the lower Midwest. First, it is unfair to make states which have already cleaned up at their own expense pay a second time to help pay for clean up in the lower Midwest. Contrary to assertions of subsidy proponents, emissions controls in many western states and many other clean states in the East go well beyond federal standards. In Wyoming, for example, we have very stringent state regulations which have forced our utilities to retrofit scrubbers on plants already burning very low sulfur coal. Several other western states have also required installation of sulfur dioxide emission controls at power plants which were already meeting federal emission standards. In the East, five states -- Minnesota, Wisconsin, New York, New Hampshire and Massachusetts -- have passed their own acid rain laws. Others such as Michigan and North Carolina have switched to lower sulfur coals to reduce their emissions. To ask all of these states to pay a second time to help the lower Midwest clean up is to penalize them for being environmental leaders. That would set a very bad precedent.

It is also important to note that the vast majority of the heaviest polluting utilities have relatively low electric rates compared to the national average. Thus, proposals to subsidize their clean up would serve to help them retain that advantage. The Alliance recently conducted a study of utility electric rates which bears this out (a copy of the study is enclosed). Our study shows that 18 of the twenty-four utilities which had at least two power plants emitting sulfur dioxide at a rate greater than 2.5 pounds per million BTUs in 1987 had average electric rates below the national average in that year. Fourteen of the twenty-four, nearly 60%, had average electric rates more than 10% below the national average. Surely, it is inequitable to have the rest of the country subsidize these utilities' ratepayers.

Subsidy proponents have rebutted our analysis with assertions that average electric rates are misleading because utilities in the lower Midwest provide an unusually large proportion of their electricity to industrial customers which are cheaper to serve. Yet, 13 of the 23 utilities we analyzed, nearly 60%, also had average residential electric rates more than 10% below the national average in 1987. No matter how you look at it, acid rain subsidies benefit utilities which have electric rates below the national average. No matter how you look at it, subsidizing these utilities is inequitable.

Extra Credit for Emission Reductions with Scrubbers

Before I leave the subject of acid rain subsidies, I want to comment on a scheme some high sulfur coal state Senators have been rumored to be considering as means of giving the lower Midwest new subsidies in acid rain legislation. As I understand it, their discussions center on an idea for giving dirty power plants double allowances for reducing emissions below the 1.2 pound emission rate standard. Perhaps worse still, they are reportedly contemplating reducing the number of plants affected by the first phase of the acid rain bill from 107 to 20 and providing a two-year extension for any of those 20 plants which meets its new standard by installing scrubbers. As I noted earlier, the current system which gives these dirty plants allowances for going below the 1.2 pound standard already represents a subsidy. Giving them double allowances just doubles the subsidy.

Moreover, as ICF's and EPA's analyses suggest, cutting phase 1 to just 20 plants, giving dirty plants double allowances for emission reductions below a 1.1 pound emission rate and giving two-year extensions for the use of scrubbers could increase the national cost of acid rain legislation by as much as 25%. The economics would be distorted by biasing the market place against the use of low sulfur coal and natural gas as emission reduction options and in favor of expensive scrubbers which protect high sulfur coal. Fuel shifts to low sulfur coal, for example, would drop from about 60 million tons a year to about 25 million tons a year in the first phase of the acid rain bill under such a plan. That is unacceptable to those of us who produce low sulfur coal, especially in light of the legacy of the percentage reduction requirements of the 1977 Clean Air Act amendments.

Clean States

The Alliance firmly believes that acid rain legislation should give additional emission allowances to power plants which are already clean, not those which are currently dirty. We would like to see an amendment which would give clean power plants partial credit for already being below the 1.2 pound emission rate.

There are several ways to give additional allowances to clean power plants without violating the 10 million ton emission reduction goal. For example, legislation could require coal-fired industrial boilers, which would not be regulated under either the President's proposal or the Senate Environment Committee's acid rain bill, to make cost-effective emission reductions. This would generate about 450,000 tons of new sulfur dioxide emission allowances which could be given to clean utility plants. A second option would be to require power plants with less than 75 megawatts of capacity to meet the same emission standards larger power plants are required to meet. That would create perhaps 200,000 tons of new emissions allowances to give to clean plants. Finally, as a recent proposal by House Energy and Commerce Committee Chairman John Dingell suggests, you could take a percentage of emission allowances created by "overcontrol" of currently dirty power plants (i.e. by reducing emissions at dirty plants below the 1.2 pound standard) and give them to clean states.

The Alliance would be supportive of any of these measures or any other means of generating additional emission allowances for clean plants. We believe clean plants in all states -- whether in the West, the South, the Midwest or the East -- should receive credit for past clean up efforts.

We in the West fear that if we are not given such credit acid rain legislation will hurt our energy industries. Because we are already so clean, there aren't many places to go in the West to find emission offsets for new power plants, even though those new power plants will be emitting at extremely low rates. We may be forced to buy emission allowances from midwestern states at great cost to our electric ratepayers. A much greater concern is that the relative absense of emission allowances in the West will put western utilities at an economic disadvantage vis-a-vis Canadian utilities which do not have to meet nearly as stringent emission standards as the Senate Environment Committee bill would impose on the West. Forcing the West to buy power from Canada, which would then be doing our polluting for us, does not help the environment and it hurts our regional economy. Similar threats could be faced in the upper Midwest and New England. That would not be in our national interest.

I should also add that the Alliance has some concerns about the so-called clean states amendment added to S. 1630 in Committee. That amendment, although intended to help states like Wyoming, will actually hurt us because it wipes out emission allowances we would otherwise receive for clean up we have carried out since 1985. One of my first decisions as Governor was to require Pacific Power and Light, our largest utility, to install a scrubber on one of its largest power plants at a cost of $80 million. As a result of that decision and Wyoming state law requiring scrubber retrofits on several other plants, Pacific Power and Light has cut emissions from its Wyoming plants by over 45,000 tons since 1985, more than a one-third cut from its 1985 Wyoming emissions level of about 125,000 tons, and will soon reduce emissions by another 16,000 tons at another Wyoming power plant. Under the basic provisions of S. 1630, they would get credit for those efforts just as utilities in other states would get credit for recent clean up efforts; however, under the clean states provision their emissions cap is based on 1996-1998 emission levels so they would receive no credit for recent clean up efforts.

The Alliance would like the clean states provision to be amended so that states like Wyoming, Montana and New Mexico can opt out of it and be regulated under the other provisions of the bill instead. We would also strongly support an amendment which would explicitly give additional credit to all clean fossil fuel-fired plants, regardless of which region of the country they are located or what fuel they burn.

NOx Emissions

The last issue I want to discuss with respect to acid rain legislation is NOx emission reduction requirements. While we support the NOx emissions cap in the Senate Environment Committee bill, we have some concerns that the NOx emission reduction requirements of the bill have the potential to force the use of selective catalytic reduction (SCR) on boiler types on which it is not cost-effective. SCR is not cost-effective on wall-fired boilers or tangential-fired boilers, although it can be cost-effective on cyclone boilers. We would support amendments which would ensure that SCR is not forced on wall- and/or tangential-fired boilers.

Visibility in National Parks

Let me turn now to the issue of visibility impairment in our National Parks. This issue has received increased attention recently because of EPA's proposal to require the Navajo power plant to reduce emissions so as to improve visibility in the Grand Canyon. Over the last month and a half, the Alliance has been developing an amendment to the Clean Air Act which would insure more rapid improvement in visibility and provide for greater state involvement in decisions to reduce visibility impairment in the national parks. Former Arizona Governor Bruce Babbitt, who serves on the Grand Canyon Trust and is an Alliance member, has been very active on this issue.

I would like to quickly outline for you what the Alliance believes is a responsible approach to the visibility problem. In a nutshell, we would like to see legislation establish regional commissions, consisting of state Governors, the EPA Administrator and the Secretary of Interior, which would be charged with developing recommendations on how to address visibility problems in a national park or a regional group of national parks. The commissions would make specific recommendations to EPA on which pollutant sources should be controlled and on what types of controls should be required. EPA would be required to either accept the recommendations or reject them and develop its own strategy for addressing visibility impairment. If a commission should fail to act on its charter within prescribed deadlines, EPA would be required to order emission reductions under its own strategy for addressing visibility impairment.

Although the recommendations of a regional commission could ultimately be rejected by EPA, we believe the concept of having a regional commission making recommendations to EPA is a vital one. Under current law, states have very little input into how the federal government addresses regional visibility problems. On the other hand, the federal government has been slow to address regional visibility problems. Our proposal would both give states the input into the process they deserve and give the federal government the political cover it needs to address visibility problems in a constructive and timely manner.

That concludes my testimony, Mr. Chairman. Thank you again for the opportunity to appear before you today. I would be happy to answer any questions you or other members of the committee may have for me.

UTILITY ELECTRIC RATES AND SULFUR DIOXIDE EMISSIONS:

A CLEAR CASE AGAINST SUBSIDIZING MIDWESTERN ACID RAIN CLEANUP

When he introduced a strong acid rain control proposal last summer, President Bush finally ended debate over whether acid rain is an environmental problem worthy of tough corrective action. He also virtually assured that we will see passage of federal acid rain legislation in the 101st Congress. Several key economic issues remain to be resolved by Congress.

The question of who should pay for acid rain cleanup costs is one of those major issues. President Bush's proposal adhered to the "polluter pays" principle. That is, those electric utilities required to reduce emissions to meet a uniform federal standard would bear the full cost of achieving that standard -- there would be no subsidies given to the highest-emitting utilities to reduce their emissions. Since the House of Representatives is using the President's proposal (H.R. 3030) as its mark-up vehicle, the principal bill in the House (which has been reported by the Health and Environment Subcommittee) also adheres to the polluter pays principle and includes no subsidies. In the Senate, the Environment and Public Works Committee modified the Administration's acid rain bill. It too is based on the polluter pays principle and includes no subsidies. The Senate bill (S. 1630) was reported out of Committee in November 1989.

In the face of the strong legislative support for the polluter pays principle, some lower midwestern Senators and Congressmen have an effort underway to amend acid rain legislation to include acid rain cleanup subsidies. They argue that because their region will be forced to bear the brunt of a national acid rain cleanup effort, they deserve to have their cleanup efforts subsidized by the rest of the country. Clean state representatives rightfully counter that they have already cleaned up at their own expense and should not have to pay again to help the lower Midwest meet their cleanup obligations. There are a number of other compelling arguments against acid rain cleanup subsidies, but one argument in particular merits greater attention than it has received thus far in this debate: the country's dirtiest utilities -- those most likely to receive subsidies under midwestern subsidy proposals -- generally have low electric rates.

This is important because subsidies will ostensibly be used to help minimize any electric rate increases which might result from reducing sulfur dioxide emissions. One might be sympathetic to this purpose if customers of the high-emitting utilities who will be incurring those costs already paid very high electric rates. Then one could argue that acid rain control requirements will disadvantage the already disadvantaged. The reality, however, is that the customers of the highest-emitting utilities have generally enjoyed low electric rates for years, largely because those utilities burned cheap, but dirty, local coal without installing pollution controls. Thus, acid rain subsidy proponents are asking the rest of the country to help high-emitting utilities retain the advantage of low electric rates. Surely that is inequitable.

High-Polluting Utilities, Low Electric Rates

Many subsidy proponents suggest that subsidies should be targetted to the select group of utilities which will be required to reduce emissions in the first phase (by 1996) of federal acid rain control plans. Under the acid rain proposals now being considered in Congress, that would mean any utility with a power plant (larger than 75 MW) which emitted sulfur dioxide at a rate greater than 2.5 lbs. per million Btu's of heat input (2.5 lbs./mmBtu). A utility's share of the subsidy pie would vary in proportion to the number of dirty plants it operates and the size of those plants (the larger and more numerous the plants are, the greater the subsidy would be).

What this all boils down to is that a relatively small group of utilities would receive the proverbial lion's share of acid rain cleanup subsidies under most subsidy proposals. As Table 1 illustrates, there are 24 privately owned utilities which emitted more than 50,000 tons of sulfur dioxide (SO2) and had at least two power plants with average SO2 emission rates of 2.5 lbs./mmBtu or greater in 1987. These 24 utilities will be responsible for a large portion of required SO2 reductions in both the first and second phases of the acid rain control program and, therefore, are likely candidates for any subsidies. They are located in the lower Midwest and certain southern states, but the vast majority (17 of 24) are concentrated in just four states: Ohio (6), Indiana (5), Pennsylvania (3) and Missouri (3). Together, these 24 utilities produced less than one-quarter of the country's electricity, but emitted more than 7.5 million tons of SO2 in 1987 -- about half of the sulfur dioxide emitted by the entire U.S. electric utility industry.

Perhaps more importantly, however, three-quarters of these utilities (18 of 24) had average electric rates in 1987 below the national average. Even more startling, almost 60% of these utilities (14 of 24) had average electric rates at least 10% below the national average; almost 40% (9 of 24) had average electric rates at least 20% below the national average. (electric rate data throughout this paper are for 1987)

Table 2 illustrates another way to examine the relationship between SO2 emissions and electric rates. It shows the average electric rate of the highest SO2-emitting utility located in 10 of the 11 highest SO2-emitting states -- the dirtiest of the dirty. (There was no data available on the electric rates of the Tennessee Valley Authority, the only SO2-emitting utility in Tennessee. Although TVA is also the largest emitter in Kentucky, the second largest, Kentucky Utilities, was listed). In every case, the highest SO2-emitting utility in each state had average electric rates which were below the national average. 70% of these utilities (7 of 10) had average electric rates more than 10% below the national average; 40% (4 of 10) had average electric rates at least 25% below the national average.

If the full projected cost of acid rain control were added to the rates of each of the companies listed in Table 2, most of them would probably still have electric rates below the national average. Table 3 shows the statewide average electric rate increases projected to result from implementation of President Bush's acid rain proposal in the top 11 SO2-emitting states. Although statewide averages can mask significant differences within a state, this data provides an important reference point for considering the impact of acid rain legislation on electric rates. Under no scenario is the average electric rate in any state projected to increase by more than 5.8%.

The issue of equity is often raised in the context of debate over acid rain cleanup subsidies. Under any acid rain subsidy proposal which is based on either a national electric tax or a national emissions tax, customers of Public Service of New Mexico, which has an SO2 scrubber on each of its power plant units and whose electric rates are 33% above the national average, would be taxed to subsidize customers of Public Service of Indiana, whose electric rates are 11% below the national average. Similarly customers of Detroit Edison, which has switched to more expensive low sulfur coal at every one of its plants and whose electric rates are 10% above the national average, would be taxed to subsidize customers of Ohio Power, whose electric rates are 32% below the national average. It is difficult to see the equity in such scenarios.

It is also important to note that one need not travel all the way from Indiana to New Mexico or even from Ohio to Michigan to see the inequities that would be caused by an acid rain cleanup subsidy program. Proponents of subsidies often present data which shows that some midwestern states have some of the highest electric rates in the country. Data on statewide average electric rates, however, can be misleading because they often mask significant differences between utilities within the same state. The state of Illinois is a classic example. Illinois has a relatively high statewide average electric rate because Commonwealth Edison, a relatively clean utility which serves Chicago and northern Illinois, has an average electric rate 30% above the national average. In contrast, Illinois Power, which produces less than one-quarter as much electricity but almost twice as much SO2 emissions, has an average electric rate 6% below the national average. This distinction is important because the biggest beneficiary of any acid rain cleanup subsidies distributed in Illinois would likely be Illinois Power, not Commonwealth Edison.

Again, under any acid rain cleanup subsidy program based on a national electric tax or a national emissions tax, Commonwealth Edison's customers, who have already paid to switch most of their plants to clean low sulfur coal, would be subsidizing Illinois Power's customers who are currently enjoying the lower electric rates that go with burning cheap, locally available high sulfur coal. It would be interesting to see whether the Illinois legislature would be willing to enact its own acid rain cleanup subsidy program forcing Chicago-area consumers to help pay for southern Illinois' acid rain cleanup. What's at work in this Illinois example is just a microcosm of the national debate on cost-sharing. A tax-based subsidy program would make those who have already paid to reduce pollution pay a second time to help those who have enjoyed the economic benefits of the lower electric rates that go with not cleaning up high sulfur coal-fired plants.

Who Has Already Paid to Clean Up?

Some Midwesterners have tried to argue that high sulfur coal states have spent more money on air pollution control than other states; therefore, the argument goes, high sulfur coal states deserve subsidies from the rest of the country to help address their contribution to acid rain. It is argued, for example, that Ohio has spent $2.1 billion on air pollution control, more than any other state. There are some serious questions about how accurately this data is collected. More importantly, however, this kind of data and argument only tells half of the story. You can't talk about money spent on air pollution control without relating the expenditures to contributions to national air pollution problems. For example, as Table 4 demonstrates, the ten highest SO2-emitting, privately-owned utilities have spent a little under $3 billion on air pollution control through 1987. That represents an average of $566 in expenditures for every ton of SO2 those utilities emitted in 1987 (5.1 million tons). By contrast, the rest of the country's utilities have spent at least three times as much, $1692 for every ton of SO2 in 1987.

The regional distribution of currently operating SO2 scrubbers sheds more light on differences in SO2 cleanup effort. About half of the scrubbers in this country are in the West (72 out of 148). In almost every case they are scrubbing low sulfur coal. Table 5 provides a state-by-state breakout of scrubber installations and the percentage of coal-fired power plants which are scrubbed. New Mexico, is scrubbing low sulfur coal at every one of its ten power plants. By contrast, Ohio has installed scrubbers on only 2 of its 110 power plants, most of which burn high sulfur coal.

Finally, it should be noted that contrary to recent assertions of acid rain cost-sharing proponents, the emissions controls in many western states and many other clean states in the East go well beyond what is required by federal law. Colorado and Wyoming, for example, recently required installation of SO2 emission controls at power plants which were already meeting federal emission standards. In the East, five states (Minnesota, Wisconsin, New York, Massachusetts and New Hampshire) have passed their own state acid rain laws. Others, such as Michigan and North Carolina have switched to lower sulfur coals to reduce their emissions. To make all of these states which have cut emissions at their own expense and on their own initiative pay a second time to help dirty states clean up would be to punish them for being leaders. That would be a bad way to begin addressing the environmental challenges of the 1990s and beyond.

Conclusions

President Bush and the Congress (to date) oppose acid rain cleanup subsidies. This paper details some of the important reasons why:

1. The vast majority of the heaviest polluting utilities have relatively low electric rates compared to the national average. Proposals to subsidize the cost of their cleanup efforts would only help them retain that advantage.
2. Acid rain controls are not projected to be exceedingly expensive. Even if they bore the full cost of their own acid rain cleanup, many of these utilities would likely still have electric rates below the national average.
3. The highest SO2-emitting utilities have spent only 1/3 as much on air pollution control, per ton of SO2 emitted, as the rest of the country.
4. Many states, both in the East and in the West, have already reduced their SO2 emissions -- at their own expense -- and have gone well beyond current federal emission control requirements in doing so. To make them pay again would be to punish them for being environmental leaders.

The Congressional debate on the subsidy issue, however, is not over. Some Midwestern Congressmen would like to amend the acid rain bills before Congress to include acid rain cleanup subsidies. In the Alliance's view, such proposals are unwarranted and inequitable. We urge continued support for the Administration's proposal and the Congressional Committee-passed acid rain bills.

TABLE 1: AVERAGE ELECTRIC RATES OF PRIVATELY OWNED UTILITIES WITH A MINIMUM OF TWO POWER PLANTS WITH SO2 EMISSION RATES GREATER THAN 2.5 LBS/mmBtu IN 1987*

Utility	1987 SO2 Emissions** (000's tons)	1987 Average Electric Rate (cents/kwh)	Variation from 1987 Natl. Avg Elect. Rt.
NATIONAL AVERAGE		6.56	
ALABAMA			
Alabama Power	346	4.92	-25%
FLORIDA			
Gulf Power	204	5.76	-12%
GEORGIA			
Georgia Power	895	5.66	-14%
ILLINOIS			
Cent. Illinois Pub. Serv.	210	6.59	0%
Illinois Power	341	6.14	-6%
INDIANA			
Indiana-Michigan Electric	118	5.76	-12%
Indianapolis Power & Light	134	4.96	-24%
N. Indiana Public Service	177	7.32	+12%
Public Service of Indiana	475	5.87	-11%
S. Indiana Gas & Electric	74	5.26	-20%
KENTUCKY			
Kentucky Utilities	177	4.59	-30%
MISSOURI			
Empire District	72	4.93	-25%
Kansas City Power & Light	159	7.08	+8%
Union Electric	383	6.49	-1%
OHIO			
Cincinnati Gas & Electric	151	5.75	-12%
Cleveland Electric	279	7.19	+10%
Columbus & Southern	129	6.06	-8%
Ohio Edison	364	6.95	+6%
Ohio Power	907	4.43	-32%
Ohio Valley Electric	483	1.67	-75%
PENNSYLVANIA			
Penn Electric	534	6.15	-6%
Penn Power & Light	312	7.23	+10%
West Penn Power	201	5.07	-23%
WEST VIRGINIA			
Monongahela Power	410	4.73	-28%

Sources: National Coal Association, Estimates of SO2 emissions from coal-fired power plants, 1980-1987, for SO2 emissions data.

Utility electric rate data provided by EPA prepared by Regulatory Research Associates, Inc., Utility Focus, May 30, 1989.

*Only utilities which emitted at least 50,000 tons of SO2 in 1987 were included in this list. Only power plants greater than 50 MW were examined.

**Emissions data cover only coal-fired power plants. Coal-fired emissions represent approximately 96% of total utility SO2 emissions.

TABLE 2:
AVERAGE ELECTRIC RATE OF HIGHEST SO2-EMITTING UTILITY IN EACH OF THE 11 HIGHEST SO2-EMITTING STATES

STATE SO2 RANK	Utility	1987 SO2** Emissions (000's tons)	1987 Average Electric Rate (cents/kwh)	Variation from 1987 Natl. Avg Elect. Rt.
	NATIONAL AVERAGE		6.56	
1.	OHIO Ohio Power	907	4.43	-32%
2.	INDIANA Pub. Serv. of Indiana	475	5.87	-11%
3.	PENNSYLVANIA Penn Electric ✓	534	6.15	-6%
4.	WEST VIRGINIA Monongahela Power	410	4.73	-28%
5.	GEORGIA Georgia Power	895	5.66	-14%
6.	MISSOURI Union Electric	383	6.49	-1%
7.	ILLINOIS Illinois Power ✓	341	6.14	-6%
8.	TENNESSEE Tennessee Val. Auth.	1286	*	*
9.	KENTUCKY Kentucky Utilities	177	4.59	-30%
10.	ALABAMA Alabama Power	346	4.92	-25%
11.	FLORIDA Gulf Power	204	5.76	-12%

Sources: National Coal Association, Estimates of SO2 emissions from coal-fired power plants, 1980-1987, for SO2 emissions data.

Electric rate data provided by EPA prepared by Regulatory Research Associates, Inc., Utility Focus, May 30, 1989.

*Electric rates data provided by EPA (prepared by Regulatory Research Associates) did not include data on TVA's electric rates.

**Emissions data cover coal-fired power plants of 50 MW or greater. Coal-fired emissions represent approximately 96% of total utility SO2 emissions. Emissions data for each utility includes emissions from all of the utility's power plants, including those located in other states. For example, TVA emissions data includes emissions from two plants in Kentucky and two plants in Alabama. TVA is actually the highest emitting utility in Kentucky as well as Tennessee; Kentucky Utilities is the second highest emitting utility in Kentucky.

TABLE 3:
PROJECTED STATEWIDE AVERAGE ELECTRIC RATE INCREASES OF TOP 11 SO2-EMITTING STATES RESULTING FROM ADMINISTRATION'S ACID RAIN CONTROL LEGISLATION (H.R. 3030/S. 1490)

State	Change in year 2000
Alabama	1.1 - 1.3
Florida	0.4 - 1.9
Georgia	1.5 - 1.8
Illinois	0.1 - 1.1
Indiana	3.6 - 4.2
Kentucky	3.1 - 3.7
Missouri	3.9 - 5.6
Ohio	3.5 - 4.4
Pennsylvania	1.5 - 1.8
Tennessee	2.2 - 2.3
West Virginia	5.1 - 5.8

The range shown in this table reflects the variation in ICF's estimates of electric rate impacts. ICF examined four scenarios for implementation of the acid rain bill including cases assuming low or high future SO2 emissions and cases assuming that extensive or limited emissions trading would occur.

Source: I.C.F. Resources Inc., Economic Analysis of Title V of the Administration's Proposed Clean Air Act Amendments(H.R.3030/S. 1490), September, 1989.

TABLE 4:
AIR POLLUTION CONTROL INVESTMENTS BY TOP 10 PRIVATELY-OWNED, SO2-EMITTING UTILITIES*

Utility	1987 SO2 Emissions* (000's tons)	Air Pollution Control Investments through 1987 (millions $)	Investments per ton of SO2 emitted in 1987 ($ per ton)
1. Ohio Power	907	377.7	416
2. Georgia Power	895	545.9	610
3. Penn Electric	534	244.4	458
4. Ohio Valley Electric	483	169.5	351
5. Public Service Indiana	475	149.1	314
6. Monongahela Power	410	107.2	261
7. Union Electric	383	260.9	681
8. Ohio Edison	364	589.5	1,619
9. Alabama Power	346	387.1	1,119
10. Illinois Power	341	75.4	221
TOTAL -- TOP 10 EMITTERS	5,138	2,906.6	566
REST OF THE COUNTRY	9,718**	16,447.4	1,692**

Sources: U.S. Department of Energy, Financial Statistics of Selected Electric Utilities 1987, DOE/EIA-0437 (87) for air pollution control investment data.

National Coal Association, Estimates of SO2 emissions from coal-fired power plants, 1980-1987, for SO2 emissions data.

*Emissions data cover coal-fired power plants of 50 MW or greater operated by state or privately-owned utilities. Coal-fired emissions represent approximately 96% of total utility SO2 emissions.

** Emissions data for "REST OF THE COUNTRY" include emissions from municipal utilities and federally operated utilities such as the Tennessee Valley Authority, but pollution control expediture data does not include expenditures from municipal utilities and federally operated utilities. Thus, the dollars per ton of SO2 spent by the "REST OF THE COUNTRY" is actually understated.

TABLE 5:
STATE BY STATE SUMMARY OF SCRUBBERS ON 1987 COAL-FIRED GENERATING UNITS

State	# of coal-fired generating units	# of Units with scrubbers		% of units w/scrub
		Installed when unit was new	Retrofit installation	
Ohio	110	2	-	1.8%
Indiana	73	9	-	12.3%
Pennsylvania	64	3	12	23.4%
West Virginia	33	2	-	6.1%
Georgia	37	-	-	.0%
Missouri	43	3	-	7.0%
Illinois	57	4	-	7.0%
Tennessee	37	-	-	.0%
Kentucky	58	7	9	27.6%
Alabama	38	2	2	10.5%
Florida	28	6	-	21.4%
Texas	32	12	-	37.5%
Michigan	72	3	-	4.2%
North Carolina	46	-	-	.0%
Wisconsin	51	-	-	.0%
Maryland	13	-	-	.0%
New York	32	1	-	3.1%
Iowa	50	1	-	2.0%
South Carolina	24	4	-	16.7%
Kansas	19	6	1	36.8%
Virginia	24	-	-	.0%
Mississippi	6	1	-	16.7%
North Dakota	12	6	-	50.0%
Wyoming	15	4	4	53.3%
Massachusetts	9	-	-	.0%
Oklahoma	10	1	-	10.0%
Arizona	12	7	1	66.7%
Minnesota	27	4	-	14.8%
New Jersey	9	-	-	.0%
Louisiana	6	1	-	16.7%
Colorado	24	4	-	16.7%
Arkansas	5	-	-	.0%
Washington	2	-	-	.0%
Delaware	5	-	-	.0%
Nevada	8	3	2	62.5%
New Hampshire	5	-	-	.0%
New Mexico	10	4	6	100.0%
Nebraska	15	-	-	.0%
Utah	12	7	-	58.3%
Montana	6	4	-	66.7%
South Dakota	1	-	-	.0%
Connecticut	1	-	-	.0%
Oregon	1	-	-	.0%

Seven states had no operable coal-fired generating units in 1987.

States are listed in descending order of their 1987 SO2 coal-fired emissions.

Source: U.S. Department of Energy, Inventory of Power Plants in the United States 1987, DOE/EIA-0095(87).

Senator WALLOP. Governor, thank you.

It is true. Wyoming in the early 1970s was in the forefront of exceeding national standards on clean air, and it came not without cost to companies in our state as well as the potential economic development of our state.

The idea that somehow our ratepayers would be asked to subsidize the ratepayers of other regions for failing to do what we have done and already paid for both through our rates and within our economy seems just grossly unfair.

It is clear to me that there is major disagreement. You heard the Senator from West Virginia. Being a coal-dependent and mineral-dependent state, they have reasons much as we do for the feelings they have. The difficulty is going to be finding a way out of it.

The principal recommendation that I gleaned from your testimony is the clean states provision. Would you be kind enough to describe for the committee the provision to opt out so that you are not penalized internally but both in terms of future growth and the present?

Governor SULLIVAN. One of the guidelines, it seems to us, is those states which have already cleaned up should not be penalized with a no growth policy; that there ought to be some credits given for the cleanup that has already taken place which equals or exceeds the cleanup that will be expected from the so-called dirty states presently existing.

The Clean States Amendment was, along with other provisions of the bill, designed to give some recognition to that, but by setting the standard in the future under the Clean States Amendment it does not give recognition to those plants such as the Pacific Power Plant that I mentioned where I required a scrubber be installed in 1987. They would be given no significant credit under the Clean States Amendment.

What we suggest is they be able to opt out and receive the 120 percent credit recognition that exists in other parts of the legislation.

Senator WALLOP. Failing to do that, it seems to me that we will have inadvertently or unknowingly created a capital asset in and amongst dirty plants in the dirty states which is the pollutant credit for cleaning up that we will have already required of our own plant and industries, for which they will get no credit. That is what you are trying to do.

Governor SULLIVAN. Absolutely, and there is a lot of talk about no national tax. That has been our position. We recognize and the Alliance and I support some recognition that there may be some inequities as the dirty plants clean up. They may be receiving some favored treatment to some degree. That in and of itself is a subsidy.

There are really two subsidies built into the legislation. One is the credit for the cleanup. That has already taken place. The other is the clean coal technology program. As we know, that has already been primarily directed toward high sulfur coal and no doubt will continue. We support the clean coal technology program to be directed toward high sulfur coal. Those are the subsidies that now exist.

The major thrust it seems to me about which we are talking is environmental legislation. We are talking about a situation where a major part of the country has taken the bit in its teeth and cleaned up. In our view, it does not seem to be the right kind of environmental ethic to suggest that if you drag your feet long enough, if you hold on long enough somebody will come along and bail you out of it.

In environmental legislation we ought to be doing everything we can to encourage people to take the lead in that area, and that is what we think the fair provisions of the administration's bill do.

Senator **Wallop**. It would seem now that not only do they bailed out but, additionally, they get rewarded under the terms.

I do not know whether your coalition has had a chance to study the legislation, but it seems that, whether intentional or not, the effect will be to slow down clean coal technology by requiring control and not being able to wait until that technology is on line or being able to use that technology which already exists.

Has the coalition had a chance to study that?

Governor **Sullivan**. I do not know. Ned Helm from the coalition is with me, and he may have a comment to make on that.

I think all we can do is recognize that that risk exists. If we are going to do clean coal technology, let us give it an opportunity to catch up.

Mr. **Helm**. I agree with the Governor.

Senator **Wallop**. I think that in advertently the legislation before us slows down and indeed hinders clean coal technology by not being patient enough to allow its use and instead requires scrubbers as a technological achievement, which has nothing to do with coal technology. It has to do with clean air technology.

Mr. **Helm**. I would feel that, in fact, it does, because you do provide a lengthened deadline for clean coal technology. You have a three-year extension for repowering and that sort of thing. In that sense it creates an incentive to use clean coal. So I think we view this bill as creating some incentives for clean coal, which is something you want to do.

Our concern would be not to move in the direction of the two-for-one allowance trading scheme that has been talked about, because I think that does exactly that of which you are afraid. It forces you to go toward scrubbers and would discourage clean coal technology.

Senator **Wallop**. I think the bill as it stands from the Senate committee does precisely that. I would hope that we would find our way to be patient enough to use the advances that have been, as the Governor points out, heavily subsidized on behalf of the American people, as well they should have been. To subsidize them and then find them unusable is the worst of all possible.

Governor **Sullivan**. To include in the bill already the sort of subtle subsidies to which I have referred and then start adding additional incentives seems to me to be going in the wrong direction.

Senator **Wallop**. Have you any figures, Governor Sullivan, such as the average rate increase to Wyoming users for the cost of controlling power plant emissions under state laws?

Governor **Sullivan**. No, I have none, Senator, except I know that when you impose $80 million for one unit of a four-unit power plant, that $80 million is in the rates and we are paying for it, and over 50 percent of our capacity is now scrubbed. So Wyoming and western consumers are paying for that technology and those steps which we have taken.

Mr. Helm. I could add, Senator, that generally putting a scrubber on adds 20 to 30 percent of the cost of a new plant.

Senator Wallop. Within the states of the coalition, is it a fair statement to say that, generally speaking, those rates are higher than the average rates of the country?

Governor Sullivan. Yes. I think Ned can correct me if I misstate it, but we have just done a study of electrical rates and determined that in the dirty states, 60 percent of those states have electrical rates that are 10 percent or more below the national average.

Senator Wallop. Let me just shift for a minute and bring something to your attention which is probably not part of the Alliance's examination but it is important to the State of Wyoming and, indeed, to all the oil and gas producing states. That is the air toxics legislation cost impact scenarios. The cost of air toxic control in the oil pacts, the production facilities—I am not talking about refining facilities, just oil and gas wells and tank storage on site—indicate that the cost for natural gas production could range from a low of $9 billion to $32 billion in capital cost.

The IBAA suggested that the $9 billion range would cause approximately 125,000 stripper wells to become commercially inviable, leading to a shutdown. Now that figure, I would think, would reflect about on a mirror image with Wyoming's production figures.

Is that about the percentage of our wells that are low production?

Governor Sullivan. I think that is correct, Senator. I only saw those figures this morning, but let me say that I do not need to tell you that they caught my attention. We have been struggling with oil production and with trying to maintain a viable oil and gas industry in Wyoming as an oil producing state, and anything, whether intentional or unintentional, that reaches in and puts an additional burden on the industry at this time is of concern to those of us in the producing states.

I have some brief comment in the written testimony about the air toxics portion of the bill relating to the cost that it may impose upon electrical power production, again without possibly resulting in the benefits and progress that is expected, particularly in the area of chlorine and hydrochloric acid, which is now shown as one of the toxics but I do not think anyone argues very heavily that that is a health hazard and that we could impose burdens on the industry without any alternative benefits.

There are certainly some toxics that need to be addressed, and we believe they should be addressed; but it ought to be very carefully done so we know what the results of those impositions are and that we do not unknowing force scrubbing or other very expensive technologies with no attendant health benefits.

Senator Wallop. You and I both know where most of the production in Wyoming is. It is not as though the average citizen of the state is wandering by there on a daily basis. Some of it is pretty remote.

Senator Ford.

STATEMENT OF HON. WENDELL H. FORD, U.S. SENATOR FROM KENTUCKY

Senator **FORD**. I got in late, and have had a chance to glance at your statement. And we are coming down to a point where nobody is agreeing on anything. And everybody has got their little piece to pick on this legislation, because it does not fit.

And at some point we are going to have to paint with a broad brush, whether it slaps on you or not. That decision is going to be made, hopefully, for the best interest of the country.

You are somewhat negative, or you expressed your opinion in a negative way as to the emission credits. And let me ask you this, Governor. If emission credits were removed, what would happen to you if you needed them when the cap was imposed or sets in?

Governor **SULLIVAN**. Well, I am not certain, one, what you mean if they were removed; and two, that I was negative. We support generally the admission credits that exist in the bill presently.

We believe that there should be some additional recognition of those states that have already cleaned up to and below the level at which the 107 powerplants are going to be expected to clean up in the next few years.

And those of us who have already done that should be recognized and receive some credits in order to avoid a total no-growth policy in the clean states that have already taken that.

I recognize there may be some inequities and that the dirty states may even get some small additional credits. We just do not think we should be penalized for cleaning up. And if by a cap on emissions and no credits you mean nobody can do anything, then I do not think that is very good policy for the country.

Senator **FORD**. Well, there is consideration being given because of the positions of so-called western states, and Malcolm knows it. We are all in this thing together. We have got to try to work it out.

And right now we find even in my state you have got the so-called low-sulfur coal and high-sulfur coal on different ends, and two senators are—I am trying to get them both together, and the other senator is taking a side. It is an election year, I guess you have to take a side here more than any other year.

But we have just got to get together on this thing. And instead of saying, no, that is not good for us, everybody is going to get a little piece of this when it comes out.

If these emission credits are not given, and there is some consideration of taking them out, I just wonder what would happen to you and to the so-called western states if the emission credits were withdrawn and the cap sets in.

Governor **SULLIVAN**. Well, if the emission credits were withdrawn, we are down to the level about as good as you can get, I think.

Senator **FORD**. Yes, but you cannot grow.

Governor **SULLIVAN**. That is what I am about to say. If emission credits were gone, then nobody builds anything. If there is additional demand for electric power we cannot provide it, at least from coal-fired generation plants. And that does not seem to me to be a very appropriate resolution of the problem.

Senator **WALLOP**. Wendell, if I may.

I think what he is saying is not that the emission credit should be withdrawn, but that there should be emission credits for states that have achieved those things, especially Wyoming since 1985. And I have the figures here. We will be down below the standards on all of those, but will not be eligible for any credits under them because we are part of the clean states.

Senator FORD. That will apply to all states. Now you are saying statewide, and we do not know whether we are going unit-wide or system-wide. It will be for all of us. I would have to disagree with my friend a little bit on that.

The point I want to make, Governor, is there is a very real possibility that the emission credit will not fly.

Governor SULLIVAN. For anyone?

Senator FORD. For anyone.

And so if those emission credits do not fly, then we have got a different proposition and a different problem out there. And our argument, as it relates to which side you are on here, as far as emission credits are concerned, then would be moot.

I would also say to you, my friend, that if the toxic section is put in, we will not have to worry about the rest of it.

Governor SULLIVAN. Well, I just made some reference to that, and my testimony makes some references to that, too. I do not think we should do it by the back door, whether it is the toxic section or something else, something that we have been unable to do through the front door.

Senator FORD. There will not be a small businessman in your state not knowing what it is going to do.

Thank you, Mr. Chairman.

Senator WALLOP. Senator McClure.

STATEMENT OF HON. JAMES A. McCLURE, U.S. SENATOR FROM IDAHO

Senator McCLURE. Thank you very much, Mr. Chairman, and thank you, Governor, for your testimony.

We are all struggling with several dilemmas.

Senator Ford pointed to the fact that there is no complete or probably never will be any complete equity in this bill. I might just point out one other problem we have. If there are, on the basis of past actions or future actions, credits to be given, that is based upon the appropriateness of the carrot part of the carrot and stick on the cleanup effort, it is partly also in recognition of the fact that the ratepayers for utilities have paid, are paying, or will pay, for the cleanup efforts. I do not see anything in the bill as it now exists that make any recognition of where those ratepayers reside.

As you know, the ratepayers in Idaho pay the bill for some of the cleanup that occurred in Wyoming.

Governor SULLIVAN. Absolutely.

Senator McCLURE. And we are also paying for some of the cleanup that has occurred in Nevada. Because that is where the generating plants are located, even though the distribution of that electricity is in the State of Idaho.

I do not know how you arrive at equity in that, but I know we are going to try. And we have to try to determine if there is a system of credits, who should get the benefit. Those who are paying the bill? Well, if so, a state like Wyoming would share credits with other areas that buy the electricity produced in the plants in Wyoming.

And I do not know how we are going to sort all of that out, or whether we can at all. But I appreciate your concern. I appreciate your constructive suggestions. And I know you will stay tuned to this station.

Governor SULLIVAN. I will. And thank you very much, Senator.

Let me just say that I agree with you fully. The carrot and the stick approach is something, surely, with this legislation, we are going to have to do to give some recognition to those plants that are coming down.

But we should not be so focused on the carrot and stick approach that we forget those that have already cleaned up and that took the lead in the environmental area and reduced the emissions in their state at costs to my taxpayers and to your taxpayers in our states.

Senator MCCLURE. Thank you very much, Mr. Chairman.

Senator WALLOP. Senator Burns.

STATEMENT OF HON. CONRAD BURNS, U.S. SENATOR FROM MONTANA

Senator BURNS. Thank you, Governor, for coming today and testifying to this committee. I also want to congratulate you as a neighbor for the leadership that you have taken in this issue. Because I think we have some similar problems, and everything like that. And I certainly appreciate that.

I do not think the question has ever been asked here, as long as I have been sitting here, on this particular issue.

In your estimation and the work that you have done, if the bill was passed today in present form, how do you and your staff see this playing out in these credits and caps? How do you see this playing out in 10 years and in 20 years? What are we looking at then?

And we think that probably emissions will come down and our air should get better. How do you see this playing out in 10 and 20 years from now? Because what we do now is going to have an effect on that. And if you could just give me an overall view of how you see this playing out.

Senator FORD. There are two bills. We keep referring to the committee bill, and there is another bill out there. There is the Administration's bill, and so we refer to this bill, and they are talking about the Administration's portion of S. 1630, whatever it might be. And so I hope you would draw a difference so that we can kind of fit your judgment into each of those.

The Senate committee bill, apparently everybody is against it, and everybody is running to the Administration bill for safe harbor.

Senator BURNS. That is a good question. I appreciate the Senator clarifying that.

Senator FORD. We ran into that yesterday, and it is hard to separate the two.

Governor SULLIVAN. Thank you, Senator.

Let me try to answer the question with some caveats, first.

Senator BURNS. You are not going to be like that one-handed economist now?

Governor SULLIVAN. I do not know about him.

Senator BURNS. Well, I only talk to one-armed economists.

Senator FORD. They cannot say what is on the other hand.

Governor SULLIVAN. Well, let me just say that my comments would not take into consideration the impacts of the toxics provision, as an example, as it now stands, which could do some things that are a little scary to me and have some economic impacts and some trading, and that I do not fully understand.

But from the straight focus on the emissions trading and that area, after the year 2010, if I understand it correctly, there will be some plants retiring and there will be some additional credits that probably are going to loosen up the credit trading a bit, and may not cause quite the hoarding that some people suggest will exist.

And of course those of us in the western states are concerned about all of the emission credits going to the dirty states, or an inordinate amount of emission credits going to the dirty states, and all of a sudden, the only credits available are over here, and they are holding them, so while we do not have a subsidy and we have talked against subsidies and we do not have a national tax, they have got all of the chips over here and we have to buy them.

That is of concern.

But if we can have a reasonable balance of credits, where there is some credit given to clean states, which I think the Administration bill and the Senate bill are trying to accommodate. And because of the retirement of the plants and the fact that the public service commissions have some control over what the utilities are able to do with their trading, it is our view that there will probably not be the hoarding that is of concern. That there will be some reasonable and responsible trading.

We have, you will see from my written testimony, and now I am getting off the bill and into some of our own suggestions. We suggested an amendment that would maintain the 10 million cap, but that would give some recognition to the efforts that the clean states have done, over and above what the Administration bill does, and try to balance out those credits a bit more than they may be now.

Senator BURNS. Now whenever we attain this, in other words, at the end of the 20-year cycle so to speak, and those credits loosen up, can you see that program fading away? Do you always see these credits staying in place and being available?

Governor SULLIVAN. I would think if there is continued growth that there would become a routine trading in those credits, because of the caps. If you are to have any growth over and above retirement, versus additional plants or changes in technology that alters that, you would always have some trading if you are going to maintain a cap.

Senator BURNS. I would ask also would you support at this point some provision for alternative fuels in this piece of legislation?

Governor SULLIVAN. I would support some provision for alternative fuels, but I am quick to say you just left me in the dust as far as knowledge or understanding of that portion of the bill.

Senator BURNS. Again, I want to thank you for taking the leadership in this. And I appreciate that very much.

Governor SULLIVAN. Thank you, Senator.

Senator WALLOP. Senator Nickles.

Senator NICKLES. I will pass, Mr. Chairman.

Senator WALLOP. Mr. Chairman, I want to express my appreciation and certainly the Governor's appreciation for your accommodation in allowing us to begin the hearing early. It was a great accommodation to us both.

STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

The CHAIRMAN [presiding]. Governor, I want to welcome you to the committee. You are very well represented in Wyoming on this committee.

Governor SULLIVAN. Thank you very much, Senator.

The CHAIRMAN. Your voice will be heard loud and clear.

Governor SULLIVAN. Thank you.

It is my privilege to appear before the committee. Thank you all very much. And I wish you well in what I know is a very complex and difficult issue.

The CHAIRMAN. Our next panel features two returning stars, Linda Stuntz and Bill Rosenberg, along with David Doniger, James Morrison, and Charles Goodman, to speak about non-attainment and air toxics.

We will begin this morning with Linda Stuntz, who of course is Deputy Under Secretary for Policy, Planning and Analysis at DOE.

STATEMENT OF LINDA G. STUNTZ, DEPUTY UNDER SECRETARY, POLICY, PLANNING AND ANALYSIS, DEPARTMENT OF ENERGY

Ms. STUNTZ. Thank you, Mr. Chairman.

It is a pleasure to be back before you again to talk about some very significant provisions in this bill, provisions that I think now are getting some of the attention that they really deserve in terms of their effects on the energy industry.

As you can tell from the length of the written testimony I submitted, we think there are a lot of these provisions that are important to the energy industry. In order to try and stay as brief as I can, I will not be able to talk about all of those but, of course would answer your questions.

Let me turn first to Title I, the National Ambient Air Quality Standards attainment provisions applicable to stationary sources. The provisions of particular concern in this Title include punitive emission fees that are imposed on major stationary sources and nonattainment areas, a change in the way that OCS emissions are regulated, some counter-productive emission offset provisions imposed on new and modernized facilities, and reduced regulatory flexibility contained in several additional provisions of S. 1630. I will be referring exclusively, at this point in my testimony, to S. 1630 and will try to draw comparisons where I can.

With respect to emission source fees, the proposed emission fees of $75 a ton for NO_x and VOC emissions alone could have a potential national economic impact of $145 million a year for electric utilities and roughly $20 million a year for petroleum refineries. Now compared to some of the billions we have been throwing around for other titles that may seem small, but again, you need to think cumulatively, and I know you are thinking that way in terms of the effects on the industry.

We have calculated, for example, that there are 109 refineries, or more than 53 percent of the refining capacity in this country that is located in nonattainment areas, at least, as of 1987. Many of these fees and restrictions, to the extent they are applicable to facilities located in nonattainment areas, will have a significant impact on refineries.

There are higher fees on major stationary sources within an ozone nonattainment area rated as serious or greater. We have talked about why we think those fees, in fact, may be perverse, because they kick in and require a 50 percent reduction or a $5,000 per ton penalty, if you do not reach attainment. If you think your area is a severe one and will have difficulty reaching attainment, we think they, in fact, will encourage major sources not to make the best available control choices. We fear that source will make poor choices and still be subject to penalties and fees, while other sources in that area did not make those choices, and that the area will still be in nonattainment.

There are a number of areas of reduced regulatory flexibility. Let me mention just one, which is of particular interest to the oil and gas industry, and that is the definition of a major source. S. 1630 reduces the threshold for that definition, provides less flexibility than does S. 1490, and, therefore, we think will draw in a larger number of very small sources, potentially even small oil and gas units, without any offsetting or contributing environmental benefits.

Let me talk about the OCS provisions, with which this committee is certainly familiar, since you have jurisdiction over the OCS Lands Act. S. 1630 would transfer responsibility for regulating emissions of OCS production facilities to EPA from Interior, where it now resides. It would make that transfer with a strong direction for further delegation of that responsibility to state and possibly local governments. It also would require that all OCS sources be treated the same as onshore sources, regardless of whether there is an impact on shore.

Platforms, for example, located more than 100 miles out in the Gulf of Mexico, would be subject to the same regulation as 100 miles or the nearest onshore source, regardless of whether there was really any impact on that source. The Administration strongly opposes this provision. We think it has the potential to allow state and local governments to impede development of federal OCS areas contrary to established law and policy. We are not aware of any environmental justification or any environmental benefits to be achieved by this provision.

The **Chairman**. Under the 1630, the regulation of OCS would go from MMS to EPA, who in turn could give it to the states.

Ms. **Stuntz**. That is correct.

The **Chairman**. Who in the case of many states would simply veto any development at all. Is that right?

Ms. **Stuntz**. We are concerned that they could. I mean, the Senate bill is a direction to the EPA, that they make a further delegation, not merely an opportunity for them to make the delegation.

Let me turn now to mobil source nonattainment and toxic provisions. We were asked by the Committee Staff not to discuss at any length the alternative fuels provision, since I have testified before you on that issue. I would be pleased to answer questions on that, but let me confine my testimony today to provisions again of particular interest to energy industries, that include lower fuel volatility standards, requirements for clean fuel buses in large urban areas, oxygenated fuel mandates, and onboard refueling vapor recovery systems.

Let me comment now just on fuel volatility reductions and refueling emissions. The Administration supports reduction in fuel volatility, because it will help reduce VOC emissions. We would note, however, that the cost effectiveness of lowering Reid Vapor Pressure for gasoline decreases as the RVP is lowered. There are minimum operating levels necessary for proper vehicle performance. We are most concerned with the potential impacts if RVP is directed to be set at lower than 9 pounds per square inch, as it is directed, for some areas, in S. 1630.

The Administration bill, by contrast, provides some flexibility that would allow cost effectiveness and vehicle performance to be considered carefully before it is directed.

With respect to refueling emissions, this Committee is no stranger to the longstanding controversy between onboard canisters and stage two. Let me just say, the Administration carefully considered the cost effectiveness and the environmental benefits of the two options and came down on the side of stage two, because it can be targeted to nonattainment areas, unlike mandatory canister requirements across the board.

Certainly there is no evidence that both systems are needed to control refueling emissions, which is the way S. 1630 is currently structured. We think this kind of a dual requirement imposes unnecessary costs and should be eliminated in favor of stage two.

Some of the mobil source provisions are also aimed at air toxic emissions, and I know Mr. Rosenberg will be able to address these in greater detail. Let me talk about two that are particularly important refineries and fuels. One is lead phasedown, and the other is diesel fuel desulfurization.

Both of these provisions will result in increased refinery energy consumption and increased cost, because of the requirement to process more barrels of oil in order to get the same volume of end products out at the other end.

Finally, in the mobil source area, let me discuss a provision of particular importance to the Administration, which is the carbon dioxide CO_2 vehicle standards contained in S. 1630. For the first time, it establishes a standard limiting the amount of CO_2 emissions from light-duty vehicle exhaust.

Since these emissions are directly related to fuel economy, the impact of this provision is to set average fuel economy standards for new gasoline-powered cars at 33 miles per gallon in 1996 and 40 miles per gallon in the year 2000. As you may recall, we are currently at 27.5. Thus, these standards are equivalent to proposing new, dramatically increased CAFE standards.

We oppose the inclusion of these standards. Certainly it is premature to mandate specific controls to address global climate change. International negotiations, as I know this Committee is well aware, are underway and need to be completed, in order for us to effectively address an issue of global dimension like global climate change.

Moreover, increased fuel economy requirements raise important nonenvironmental questions that have to be carefully considered, such as feasibility, cost, and competitiveness of the U.S. automobile industry with foreign manufacturers.

Finally, our analysis does not support increases in fuel efficiency to this level as technically feasible within these time frames. Therefore, we strongly oppose those provisions and urge that they be deleted from the Senate bill.

Let me turn, finally, to the air toxics title. As we discussed yesterday, and I wholeheartedly concur with Senator Ford's statement, the air toxic provisions of S. 1630, if left unamended, in some ways will make the whole acid rain title irrelevant. Because if you have to scrub electric utility emissions to get at chlorine and all the other trace toxic gases that exist, you will have to go to such a level of control that the standards for acid rain, 1.2 and 2.5 pounds of SO_2 per million BTU, are irrelevant. They are basically superseded.

Under the particulate standard virtually every utility would have to apply bag houses. The cost of that ranges in the billions. I know we have someone with us today from the Southern Company who will address this in greater detail from the utility perspective. So, I will not belabor that in any more detail. But I think it is critical that in order to understand why the air toxics provisions of S. 1630 are so dramatically more burdensome to the utility industry than the provisions of S. 1490, you need to understand that the Administration bill requires that special studies be carried out before utility toxic air emissions are regulated. Therefore cost benefit and environment improvements to be achieved by application of these costs and technologies can be considered. The regulatory program can be tailored where it is truly appropriate and important.

That flexibility is gone from the Senate bill. The only flexibility contained is that chlorine emissions are explicitly not to be regulated for three years. Everything else, and there are many other elements, apparently is to be regulated immediately, because there is no flexibility. All stationary sources that emit any of the toxic air emissions are to be regulated under a maximum available control technology standard.

The oil and gas industry also is severely affected by the Senate's air toxics provision. A four oil well lease, for example, which is a pretty small one, emits somewhere in the nature of 10 pounds per year of benzene. Under the Senate's air toxics provision, that four oil well lease could be required to impose controls ranging as high as $100,000 a year. This would achieve little, if any, environmental benefit.

These estimates are probably high. Under the Administration's bill, that the EPA would have the flexibility again to take into consideration a cost benefit relationship. That flexibility does not exist in the Senate bill. As a result, there will be a substantial impact on stripper well production.

This Committee is well aware of the tight economics involved when you are dealing with a well that produces two or five or nine barrels of oil a day. The level of control that may be required to comply with a maximum available control technology standard, and the additional costs for that, are simply not compatible with the economic return on a nine barrel a day oil well.

So, in closing, let me say that we think there are billions of dollars at stake in this air toxics title. We appreciate and welcome the Committee's inquiries in these areas, both for their effects on the oil and gas industry and on the electric utility industry, and I look forward to your questions.

[The prepared statement of Ms. Stuntz follows:]

SUMMARY OF LINDA G. STUNTZ'S TESTIMONY BEFORE THE COMMITTEE ON ENERGY AND COMMERCE SUBCOMMITTEE ON ENERGY AND POWER

The Nation's increasing dependence on imported petroleum is a serious problem that must be addressed by a balanced, integrated energy policy. The transportation sector, because of its importance to U.S. oil consumption and because it contributes one-third of U.S. CO_2 emissions, must be an important part of that energy strategy.

The Department has investigated the potential for cost-effective fuel efficiency improvements. We have concluded that additional automobile fuel economy improvements are technologically feasible. These improvements can be brought about by the increased use of existing technologies such as overhead camshafts, roller cams, multi-point fuel injection, 4-valve per cylinder engines, electronic transmission controls and reduced friction. We have provided answers to specific questions from the subcommittee on our estimated range of "reasonable" fuel economy. We define a "reasonable" level of achievable fuel economy to be one that reflects:

1) Proven capability of technologies to improve fuel economy,
2) regulatory requirements (emission and safety),
3) consumer choices for automobiles and light trucks and,
4) manufacturers' near-term product plans.

Based on this definition, we have estimated that a reasonable range of automobile fuel economy is 29-31 mpg by MY 1995, and we have estimated that a reasonable range of light truck fuel economy is 22-23 mpg by MY 1995. These estimates are not intended to be a basis for establishing higher fuel economy standards. Fuel economy requirements must reflect more factors and issues than are reflected in our answers to the subcommittee's technical questions.

The Administration is reviewing oil conservation policy options as part of its development of a national energy strategy. This strategy will aim for a balance of energy efficiency improvements, increased domestic energy supply, a reasonable mix of reliable and diverse energy sources, and protection of the environment. The Secretary of Energy is committed to the development of this integrated national energy strategy and has called for increased national attention to conservation.

STATEMENT

OF

LINDA G. STUNTZ

DEPUTY UNDER SECRETARY FOR
POLICY, PLANNING AND ANALYSIS

U.S. DEPARTMENT OF ENERGY

BEFORE THE

COMMITTEE ON ENERGY AND COMMERCE

SUBCOMMITTEE ON ENERGY AND POWER

UNITED STATES HOUSE OF REPRESENTATIVES

JULY 13, 1989

I am happy to have the opportunity to appear before this subcommittee today to discuss our technical potential to achieve higher levels of automobile fuel efficiency. In the testimony I am presenting, I have attempted to respond to the very specific questions asked by the Subcommittee. These questions were not asked in the context of specific fuel economy policies, such as corporate average fuel economy (CAFE) standards. Therefore, the information I am providing is not intended to be a basis for establishing higher fuel economy standards. As I explain later, fuel economy requirements must reflect more factors and issues than are reflected in answers to these technical questions.

TECHNICAL FEASIBILITY IN PERSPECTIVE

The Administration shares the committee's interest in encouraging sound energy conservation. With that objective in mind, let me make three important points to help put the remainder of my testimony in perspective.

First, there is an important distinction between technical and commercial feasibility. It is technically feasible to make cars that achieve up to 100 miles per gallon efficiency. However, such a car is unlikely to be commercially feasible if it cannot meet the demands that consumers place on it such as size, performance, and comfort. In addition, the car must also satisfy regulatory requirements governing safety and emissions.

Second, in discussing what may be technically and economically feasible, it is important to keep accountability, uncertainty, and risk in mind. While government estimates and projections are necessary to evaluate appropriate policies, when they are used to regulate or otherwise govern economic decisions, projections that are wrong can lead to costly mistakes. Therefore, we should be cautious in taking today's "reasonable estimates" and basing the future competitiveness of U.S. industry on them.

Third, we need to have clear objectives in establishing a policy to improve automobile efficiency. As we develop our national energy strategy, we intend to address why we should reduce petroleum consumption and identify the most cost-effective methods to do so.

IMPORTANCE OF AUTOMOBILE FUEL EFFICIENCY

Our Nation's increasing dependence on imported petroleum is a serious problem that should be addressed by a balanced, integrated energy policy.

The transportation sector plays a crucial role in U.S.

petroleum dependence. Oil use by the transportation sector in 1988 exceeded 10 million barrels per day (MMB/D), up more than 2 percent from 1987, and almost 20 percent higher than in 1973. The combined effects of increased oil consumption and declining domestic production have increased U.S. oil imports for 1988 to 7.2 MMB/D.

In 1973, the average domestic new car traveled only 14 miles on a gallon of gasoline. By 1988, the average domestically produced new car achieved a fuel efficiency of more than 27 miles per gallon. This extraordinary accomplishment of American industry placed U.S. average new car fuel economy on a par with that of Europe and Japan, where fuel prices are two to three times what American motorists pay.

While fuel economy gains have prevented U.S. oil consumption from being substantially higher, automobile sales data for 1987 and 1988, and preliminary estimates of automobile sales for the first six months of 1989, indicate that fuel economy progress has stalled. Consumers no longer rate fuel economy as a primary factor in selecting an automobile and have become more indifferent to the importance of improving fuel economy. In addition, sales of light trucks and vans have increased over the last several years as consumers purchase them in lieu of automobiles for service that only occasionally requires the utility of a truck or van. Consequently, light-truck fuel consumption has grown to be about 30 percent of total light-duty vehicle fuel use.

The Administration has taken steps to address the leveling off of automobile fuel economy. First, the decision was made to set the model year (MY) fuel economy standard at 27.5 mpg (up 1 mpg over the MY 1989 requirement). In addition, the national energy strategy we are developing will include an evaluation of policies to improve energy efficiency, including cost-effective automobile efficiency improvements.

TECHNICAL POTENTIAL TO IMPROVE AUTOMOBILE FUEL ECONOMY

Between now and the year 2000, improved automobile and light truck fuel economy is technologically feasible. But technological feasibility is only one of a number of critical factors that confront vehicle manufacturers in their planning for future product lines. Consumer demand, energy prices, competitive forces, and safety and environmental regulations are factors that must be considered. Many of these are uncertain.

Among the technologies that can be used to improve fuel efficiency are front-wheel drive, weight reduction, overhead camshafts, roller cams, multi-point fuel injection, multi-valve four-and six-cylinder engines, electronic transmission control, new transmission designs, aerodynamics, reduced accessory drag and improved lubricants and tires.

"REASONABLE" RANGES OF NEW CAR AND LIGHT TRUCK FUEL ECONOMY

The subcommittee asked DOE to address the issue of "reasonable" achievable levels of fuel economy for cars and light trucks in 1995 and 2000. The Department has responded to the subcommittee's request by providing these estimates for domestically produced automobiles. However, it is very important to understand that these estimates are not to be construed as the Department's assessment of what future fuel economy standards for cars and light trucks should be. Our ongoing analysis of the technological potential to improve fuel economy is only one part of the CAFE rulemaking process. CAFE regulations are administered by the Department of Transportation (DOT). DOT has the broad mandate to assess all of the rulemaking criteria, including factors that are not reflected in DOE's analysis. We also note the important point made by DOT in its testimony that future fuel economy potential should consider other factors, including consumer acceptance. We agree with this point and want to reemphasize it here. However, to accommodate the subcommittee's request for our estimates, we are providing our current estimates of "reasonable" future fuel economy.

Since future consumer demand can not be confidently predicted, our estimate of what is "reasonable" is offered as a range which takes into account this uncertainty. "Reasonable" should also take account of current manufacturer product plans. This is particularly important when estimating 1995 fuel economy since existing product plans have already determined many of the model line and engine offerings for MYs 1991 - 1993. In addition, planning for MYs 1994 and 1995 is well advanced.

"Reasonable" should also reflect the impact of the President's clean-air plan which tightens emission requirements for passenger automobiles and light trucks. Therefore, we define a "reasonable" level of achievable fuel economy to be one that reflects:

1) Proven capability of technologies to improve fuel economy,
2) regulatory requirements (emission and safety),
3) consumer choices for automobiles and light trucks and,
4) manufacturers' near-term product plans.

Based on this definition, we have estimated that a reasonable range of automobile fuel economy is 29-31 mpg by MY 1995. Similarly, we have estimated that a reasonable range of light truck fuel economy is 22-23 mpg by MY 1995. We do not have estimates for MY 2000 since we have not completed that analysis.

The relatively narrow range of fuel economy estimates provided for MY 1995 reflects existing manufacturer product plans. Furthermore, these estimates do not fully reflect the requirements of the President's clean-air plan. We are now evaluating the impact that proposed tighter emission requirements will have on this estimated range.

"ACTUAL" LEVELS OF FUEL ECONOMY

The Subcommittee also requested that DOE identify the factors that will affect the "actual" levels of fuel economy achieved by cars and light trucks. As previously discussed, many factors, including consumer choice, are the ultimate determinates of actual fuel economy. In the recent past, we have witnessed consumer trends towards use of light trucks as personal vehicles, towards increased performance as expressed in horsepower-to-weight ratios or measured vehicle acceleration, and towards heavier, more luxurious vehicles - both cars and trucks. We have also seen increased use of fuel economy technologies which have prevented these other trends from jeopardizing our fuel economy progress. These potentially offsetting forces - consumer preferences and continued use of more advanced technologies - are a source of uncertainty in estimating future fuel economy.

In addition, the current CAFE law, modified by the Alternative

Motor Fuels Act of 1988, will provide manufacturers opportunities to change their CAFE by manufacturing alternative-fueled vehicles. Manufacturers can also change the relative domestic vs. imported content of vehicles that are currently classified as domestic or imported. These changes in CAFE would not affect the actual fuel economy of cars purchased and used, but do affect manufacturers' compliance with CAFE standards.

Finally, actual fuel economy in use depends on the mix of new and old cars on the road and the difference between the EPA tested fuel economy and that achieved in operation. Our estimates of fuel consumption account for estimated future sales of new vehicles and estimated retirements of older vehicles. Based on test results, we have also included a factor to translate EPA tested to "on-road" fuel economy. Our estimate is that average on-road fuel economy is about 15 percent lower than EPA tested fuel economy.

IMPACTS ON PETROLEUM CONSUMPTION

In response to the subcommittee's inquiry pertaining to petroleum consumption, we have prepared an attachment, Table 1, which shows how we expect U.S. petroleum consumption to change in response to higher or lower automobile and light truck fuel economy. We have calculated, for the low and high estimates of "reasonable" fuel economies for cars and light trucks in MY 1995, our estimate of highway motor fuel consumption in 2000, 2005 and 2010. We have also assumed, for the purposes of this calculation, a range of MY 2000 automobile fuel economy of 33-38 mpg (low to high). This fuel economy range (for MY 1995 - MY 2000) implies that, in 2005 for example, fuel use would be 420 thousand barrels per day greater if the low-range fuel economy were realized as compared to the high-range fuel economy. However, the low-range fuel economy still provides 760 thousand barrels per day fuel savings when compared to no change in fuel economy (also for 2005). In order to provide these estimates, many assumptions were necessary to estimate future automobile sales, vehicle miles of travel and fleet composition. In addition, the savings estimates are relative to specific baseline comparisons and do not represent savings that would result from any policy, such as increasing CAFE standards.

VEHICLE FLEET COMPOSITION

Our estimates of future fuel economy are based on the current mix of vehicle sizes and the current mix of automobiles and light trucks. As these change, so also would the the range of fuel economy that we can reasonably expect. Past experience has shown that the interior space of passenger automobiles has remained more or less constant after a slight decline from 1979 - 1980.

However, exterior size, weight and engine size have all declined significantly in U.S. automobiles. This reflects the space efficiency of the newer front-wheel drive automobiles over the previous rear-wheel drive models, and reductions in vehicle weight from front-wheel drive configuration and other factors. It also reflects the ability of smaller engines to power lighter automobiles, and increased horsepower from smaller engines. We do not expect that future automobiles will depart significantly from the current situation although the actual pattern of vehicle sales by size class will undoubtedly show some variation and may vary significantly more than past trends would indicate.

COST EFFECTIVENESS OF FUEL ECONOMY TECHNOLOGIES

It is our view that the increased use of existing fuel economy technologies such as 4 speed automatic transmissions, torque-converter lock up, electronic transmission control, fuel injection, overhead camshafts, and 4-valve heads can provide fuel economy benefits that are paid for by reduced operating costs. We estimate that these technologies can increase automobile fuel economy to about 34 mpg and increase vehicle costs no more than would be repaid by lower fuel costs (assuming $1.10 per gallon gasoline price). However, to reach these higher fuel economy levels in MY 1995, manufacturers would need to alter existing product plans so significantly as to substantially increase the cost of fuel economy technologies relative to the cost of introducing these technologies in a planned and orderly way. Therefore, at this point in time, we do not believe that levels above 31 mpg can be achieved by MY 1995 without increasing consumer costs more than would be repaid by estimated fuel savings.

The cost effectiveness of improving fuel economy declines as technologies are used more intensively. For example, advanced materials, more extreme reductions in aerodynamic drag and intake-valve controls can be used to push fuel economy to even higher levels. But the increased cost to the consumer is not as likely to be recovered in lower operating costs except at higher fuel prices.

FUEL ECONOMY AND AUTOMOBILE EMISSIONS

Certain automobile technologies, such as electronic engine controls and fuel injection, have both increased fuel economy and lowered emissions. However, these technologies have either been incorporated into current automobiles or will be largely incorporated by MY 1993-1995. Lower emissions of hydrocarbons, CO, and NO_X can be achieved in ways that will lower fuel economy or may be achieved using new technologies that have no fuel economy penalty. However, it is likely that trade-offs between lower fuel economy and lower emissions will be made by manufacturers attempting to meet tighter standards. It is difficult to forecast the actual impact of tighter emission standards on fuel economy because this will depend on the degree to which new technologies can be developed that can satisfy these tighter requirements without reducing fuel efficiency.

GREENHOUSE GAS EMISSIONS

Unlike emissions of CO, NO_X, and HC, emissions of CO_2 are proportional to the fuel used per vehicle mile of travel. Increased fuel economy is, therefore, the only known way to change gasoline powered vehicles so as to reduce CO_2 emissions on a vehicle-mile basis.

U.S. transportation currently contributes about one-third of the energy-related CO_2 produced in the U.S. and about 7 percent of the energy-related CO_2 in the world. U.S. passenger automobiles and light trucks account for almost two-thirds of this or over 4 percent of world wide energy-related CO_2 emissions.

If fuel economy did not improve, U.S. energy-related carbon emissions would increase from 255 trillion grams (1988) to 347 trillion grams (2010) (a 36 percent increase). If the the "low-range" estimate of car and light truck fuel economy occurred, energy-related carbon emission would be reduced to 311 trillion grams (a 22 percent increase from 1988 to 2010). If the "high-range" fuel economy estimate occurred, energy-related carbon emission would be reduced to 291 trillion grams (a 14 percent increase from 1988 to 2010). These estimates are displayed in the attached Table 2.

CONCLUSION

Past achievements in increased domestic energy production, fuel substitution, and greater energy efficiency have contributed to lower prices and abundant oil supplies. The Administration intends to emphasize the value -- both to the economy and to the environment -- of cost-effective energy conservation.

The transportation sector, because of its reliance on petroleum-based fuels and because of the size of its oil consumption, is a key element in the Administration's energy policy. The Administration is reviewing oil conservation policy options as part of its development of a national energy strategy. This strategy will aim for a balance of energy efficiency improvements, increased domestic energy supply, a reasonable mix of reliable and diverse energy sources, and protection of the environment. The Secretary of Energy is committed to the development of this integrated national energy strategy and has called for increased national attention to conservation. I hope that the information that I have provided the Committee today will help the Congress in its deliberations on these same issues.

This concludes my prepared remarks. I would be happy to answer any questions that the subcommittee may have.

Table 1

Motor Fuel Consumption of Different Levels of Fuel Economy (MMB/D)

YEAR	No Change in Fuel Economy	Low-Range Fuel Economy	High-Range Fuel Economy	No-Change to Low-Range Savings	Low-Range to High-Range Savings
1988	6.56	NA	NA	NA	NA
2000	7.73	7.25	6.99	0.48	0.26
2005	8.41	7.65	7.23	0.76	0.42
2010	8.94	8.01	7.50	0.92	0.52

NOTES:

"No change" in fuel economy is 27.5 mpg in MY 1988 to MY 2000 for passenger automobiles and 20.5 mpg in MY 1988 to MY 2000 for light trucks.

The "Low Range Fuel Economy" is 29 mpg in MY 1995 and 33 mpg in MY 2000 for passenger automobiles and 22 mpg in MY 1995 to MY 2000 for light trucks. "Straight-line" increases between 1988 to 1995 and 1995 to 2000 fuel economy levels are assumed.

The "High Range Fuel Economy" is 31 mpg in MY 1995 and 38 mpg in MY 2000 for passenger automobiles and 23 mpg in MY 1995 to MY 2000 for light trucks. "Straight-line" increases between 1988 to 1995 and 1995 to 2000 fuel economy levels are assumed.

These estimates are for domestically produced vehicles. The fuel economy of all vehicles purchased in the U.S. is slightly higher.

All fuel economy levels are held constant after MY 2000.

Table 2

Carbon Emissions of Different Levels of Fuel Economy (trillion grams of carbon per year)

YEAR	No Change in Fuel Economy	Low-Range Fuel Economy	High-Range Fuel Economy	No-Change to Low-Range Savings	Low-Range to High-Range Savings
1988	255	NA	NA	NA	NA
2000	300	282	272	19	10
2005	327	297	281	29	16
2010	347	311	291	36	20

NOTES:

"No change" in fuel economy is 27.5 mpg in MY 1988 to MY 2000 for passenger automobiles and 20.5 mpg in MY 1988 to MY 2000 for light trucks.

The "Low Range Fuel Economy" is 29 mpg in MY 1995 and 33 mpg in MY 2000 for passenger automobiles and 22 mpg in MY 1995 to MY 2000 for light trucks. "Straight-line" increases between 1988 to 1995 and 1995 to 2000 fuel economy levels are assumed.

The "High Range Fuel Economy" is 31 mpg in MY 1995 and 38 mpg in MY 2000 for passenger automobiles and 23 mpg in MY 1995 to MY 2000 for light trucks. "Straight-line" increases between 1988 to 1995 and 1995 to 2000 fuel economy levels are assumed.

These estimates are for domestically produced vehicles. The fuel economy of all vehicles purchased in the U.S. is slightly higher.

All fuel economy levels are held constant after MY 2000.

STATEMENT OF

LINDA G. STUNTZ

DEPUTY UNDER SECRETARY FOR
POLICY, PLANNING AND ANALYSIS

U.S. DEPARTMENT OF ENERGY

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

January 25, 1990

INTRODUCTION

I am happy to appear before this committee today to discuss the energy policy implications of Title I - Stationary Source Nonattainment and Title III - Air Toxics, of S. 1630, the Clean Air Act Amendments, on the electric utility and the oil and gas industries. I will also comment on selected provisions of Title II - Mobile Sources. These provisions would reduce both toxic air emissions and emissions that can affect the attainment of the National Ambient Air Quality Standards (NAAQS). As appropriate, I will compare these provisions to similar provisions in S. 1490, the Administration's proposed amendments to the Clean Air Act.

I. NAAQS ATTAINMENT PROVISIONS (TITLE I)

An area is in nonattainment for a specific pollutant if, based on a set of criteria established by EPA rulemaking, one or more monitors in an area demonstrate that the federally set NAAQS has been exceeded. S. 1630 nonattainment provisions of concern to energy industries include:

- Punitive emission source fees imposed on major stationary sources for each ton of emissions generated in nonattainment areas;

- A change in the way Outer Continental Shelf (OCS) emissions are regulated;
- Counterproductive emission offset provisions imposed on new and modernized facilities; and,
- Reduced regulatory flexibility contained in several additional provisions.

These provisions are applicable to many industries that produce volatile organic compounds (VOC), nitrogen oxides (NOx), carbon monoxides (CO) and particulate matter (PM), including the oil and gas industry and the electric utility industry.

Emission Source Fees

S. 1630 would impose a source fee of not less than $75 for each ton of NOx, VOCs, CO and PM10 emitted by major stationary sources, including many electric utility and oil and gas utilities in nonattainment areas. The proposed emission fees on NOx and VOC emissions could have a potential national economic impact of $145 million/year for electric utilities and roughly $20 million/year for petroleum refineries (assuming the minimum charge of $75 per ton; 305 utilities burning coal, petroleum and natural gas and 109 refineries located in nonattainment areas).

Similar fees would apply to CO and PM10 emissions, causing additional cost to units operating in nonattainment areas. These source fees are in addition to permitting fees collected for administering the added requirements of the nonattainment program.

For these two categories of fees associated with new nonattainment provisions, the Administration estimates the cost of S.1630 to be $755 million and the cost of S.1490 to be $300 million in 1995. The difference is the added source fees.

Section 183(b) of S. 1630 places additional and still higher fees on major stationary sources that are within an ozone nonattainment area rated as serious or greater, if that area does not reach attainment status by the prescribed year (2000 for serious; 2005 for severe and 2010 for extreme). Starting from the designated year of attainment, each stationary source must reduce its VOC emissions by 50 percent or pay a fee of $5000 per ton of VOCs emitted above the 50 percent level in the prescribed attainment year. This fee would be assessed annually until the area reaches attainment.

As constructed, Section 183 may have the perverse consequence of delaying emission reductions, particularly in the most severe ozone nonattainment areas. Let's assume that a major stationary source prior to the prescribed year of attainment uses every technological method to reduce its VOC emissions prior to this year, but the ambient standard is not attained in the area because other sources have not applied such extensive controls or for an even less controllable reason. This new fee would be imposed on this source even though there is no technical recourse except to cut economic production. The owner of the source is liable for this added fee until other sources cut their emissions sufficiently for the area to meet the nonattainment standard. Thus, if it is believed that an area will have difficulty reaching attainment status, Section 183 will actually encourage major stationary emissions sources in the area to maintain as high a level of VOCs as possible up to the prescribed attainment year. Then, technology could be applied to reduce or escape the fee. Clearly, an arbitrary rule that does not recognize the amount of effort taken by an individual major facility to reduce VOC emissions can be environmentally counterproductive.

While S. 1490 has a similar fee for major sources in areas that do not meet the prescribed attainment schedule, it has several relief features, compared to S. 1630, for the well controlled facility:

- First, the baseline for the fee is the excess emissions above 80 percent, not 50 percent, of the emissions of the unit for the baseline year.

- Second, the level is set based on the lower of allowable or actual emissions of the source in the prescribed year so that higher fees are placed on sources that have not made their permit commitments, which will hasten the area reaching compliance.

- Third, only the severe nonattainment area category is covered by this provision in S. 1490. Thus, S. 1490 subjects sources in not more than four areas to this potential penalty and only after the year 2010. S. 1630 would place this fee on sources in the serious nonattainment areas that do not reach attainment in the year 2000, (a possible total of 36 areas) on three more areas in 2005 (the severe regions) and one area in 2010.

The emission source fees would result in differential economic competitiveness between sources in attainment and nonattainment areas. This would occur even after sources in nonattainment areas have taken emission control steps well beyond emissions control efforts by similar facilities in areas that have been in attainment since the Federal ambient standards were put in place. While electric utilities may be able to transfer these added costs to the consumer through the rate setting process, oil and gas producers with wells located in nonattainment areas and refiners, will suffer economically.

We have not yet been able to quantify these adverse consequences in terms of energy production or refinery activities. On a national basis, the impact appears small, but will depend on:

- Refiners' or producers' financial strength;
- Emissions quantities, and therefore, the amount of the annual fees;
- Potential to have the area reach attainment by the prescribed date (the Section 183(b) added fee); and
- Ability to transfer these costs to product prices.

Outer Continental Shelf (OCS) Treatment

Currently, regulation of emissions from OCS production facilities are managed by the Department of the Interior under authority granted in the OCS Lands Act. S. 1630 would grant authority for enforcing environmental regulations for oil and gas production activities on Federal OCS lands to EPA, with strong direction in the bill for further delegation to State and possibly local governments. Should this happen, facilities could incur unwarranted project delays. There is also a potential for a State or locale to use the authority to impede development in the Federal OCS area, contrary to established Federal law and policy. For this reason, the Federal Government has strong reservations about giving non-Federal entities jurisdiction over an element of a Federal program conducted exclusively outside State boundaries.

In addition, S. 1630 would require all OCS sources to be treated the same as onshore sources, regardless of whether there is an impact onshore. For example, platforms located more than 100 miles offshore in the Gulf of Mexico would be regulated under the same standards as those located onshore. This regulatory approach could have serious energy production implications, particularly in the Gulf of Mexico. It could make some marginal production uneconomic and subject to abandonment at a time of decreasing domestic production, taking actions of this sort are ill-advised, particularly without attendant onshore air quality improvements. The Administration believes that existing law provides adequate authority to regulate air emissions and, for the reasons stated above must oppose Section 111 of S. 1630.

The Emissions "Offset" Provisions

For a new source of emissions locating in a nonattainment area, the added emissions from that source may be required to be offset -- that is, the level of emissions from one or more current sources in the area must be reduced by an amount that will offset any added emissions due to operation of the new source. In some cases, the offset is greater than one to one. For example, if a permit requires a 1.5 to 1.0 offset, every two new tons of emissions must be offset by a reduction of three tons of emissions from present sources in the area.

The stringent offset provisions contained in S. 1630 (at levels greater than one to one) may have an unnecessarily adverse impact upon the replacement and modernization of plants, including energy-related facilities, in many locales. The specific requirements in S. 1630 for VOC, CO, and PM offsets of 1.5 to 1 to 2 to 1 in many nonattainment areas add an additional burden in terms of both costs and time delays for a facility seeking to expand, modernize, or begin a new operation. For S. 1630, this burden may delay projects while the additional offsets are obtained -- whether they are obtained internally by reducing emissions from a facility owned by the same business, or externally through purchase of emission reductions from another source. In either event, the cost of the new or modernized project escalates, and may be sufficient to impair its economic viability. For some areas, it may be impossible to obtain offsets because of other actions being taken to reduce VOC emissions at present facilities.

This offset requirement in all PM nonattainment areas, and in those ozone and CO nonattainment areas that are given at least 10 years to demonstrate compliance, is added to requirements contained in both S. 1630 and S. 1490 that an approvable State Implementation Plan must show annual emission level reductions in the contributing pollutants throughout the period for which an attainment extension is granted. Further, for any new plant or one with increased emissions due to expanded operations, this is an added requirement to the major source emission fees and to the added fee placed on emissions if the area does not reach attainment status on the prescribed date.

Reduced Regulatory Flexibility

S. 1630 contains a variety of provisions which reduce or eliminate flexibility for Federal and State agencies to tailor plans, programs, and sanctions to specific air pollution problems. Examples of these less flexible provisions include:

- o Designation of nonattainment areas -- Areas violating the ozone, CO, and PM 10 NAAQS would be designated as nonattainment areas as a matter of law without any consideration of specific circumstances in identification, characterization and reporting of emissions.

- o The major VOC stationary controls provisions for ozone nonattainment areas classified as serious or greater define "major" VOC sources to include smaller sources than in S. 1490, for example, individual oil and gas wells, without any consideration of cost-benefit.

- o Mandatory sanctions -- All sanctions in the bill must be imposed when a State fails to satisfy a requirement. No consideration is made as to whether reasonable efforts are being made by the State to address a nonattainment problem or how effective a specific sanction will be in addressing the ambient air problem.

- Ozone transport regions -- Both proposals contain provisions that recognize the importance of interstate ozone transport, and thus the need for Regional Transport Commissions to assess the problems and develop strategies. However, despite recent findings that region-wide control of VOC emissions in nonattainment areas may be of limited value, S. 1630 presumes the need for certain measures (Inspection/Maintenance (I/M) and Reasonably Available Control Technology (RACT) programs) throughout a region before further evaluation of the problem and other strategies. Further, in S.1630, these Commissions appear to supercede individual State authorities. The Administration believes the regional commissions will be best suited to make recommendations on additional controls needed in the regions or for parts of a region. These recommendations would then be considered by States and by EPA in formulating their required actions. The S. 1630 provision is likely to lead to costly over-control in some areas of a transport region with small or no environmental benefit. The Administration has estimated these added costs for the year 2000 to be $300 million.

- Emissions from consumer and commercial products -- S. 1630 mandates at least a 3 percent reduction in national VOC emissions from these products without first studying the feasibility and effectiveness of the control methods and reduction efficiencies.

These are examples of how S. 1490 offers more flexibility, with attendant potential lower costs, to achieve similar emission reductions than does S. 1630.

In sum, the primary differences between S. 1630 and S. 1490 in the ozone air quality standard nonattainment provisions are that S. 1630 would assess high emissions fees per ton of pollutant produced in nonattainment areas; impose regulatory requirements that are difficult to meet and that may be determined to be unnecessary, given other control measures; and would reduce regulatory flexibility considerably.

II. RELATED MOBILE SOURCE PROVISIONS (TITLE II)

Pursuant to the Committee's request, this portion of our testimony deals with the mobile source provisions of Title II of S. 1630 which will affect ozone nonattainment, air toxic emission levels, and CO2 emission limits. This testimony does not discuss the President's Clean Fuels initiative, contained in Title II of S. 1490, which was the subject of a previous Committee hearing.

Many of the Title II provisions in S. 1630 are intended to lower atmospheric ozone by reducing mobile source emissions of ozone precursors -- reactive hydrocarbons (HC) and nitrogen oxides (NOx). Those provisions of particular interest to energy industries include:

- The fuel volatility standard which lowers gasoline Reid Vapor Pressure (RVP) during warmer months;
- Requirements for clean fuel buses in large urban areas; and,

- Onboard refueling vapor recovery systems.

These S. 1630 provisions are discussed below.

Fuel Volatility Standards (RVP)

A fuel volatility standard which lowers summertime gasoline Reid Vapor Pressure (RVP) maximum levels will result in vehicles emitting less evaporative HC emissions. The reduction of gasoline RVP would be accomplished by removing portions of aromatics such as butane from gasoline. This in turn would result in additional costs to the refiner. These refinery costs increase as RVP is lowered. The Administration has estimated the cost of this provision in the year 2000 would be $260 million and would result in a 7.6 percent reduction in national ozone ambient levels. The cost-effectiveness of lowering gasoline RVP decreases with decreases in RVP. We are most concerned with the potential impacts if RVP is set lower than 9.0 psi for some areas. We would propose that greater discretion for analyzing the consequences of, and the need for, setting any such level be provided to the EPA Administrator.

Clean Fuel Buses

The use of clean fuels in buses in urban areas of 1 million people or more (and in light duty vehicles as proposed in S. 1490) would result in lower levels of relative HC emissions and NO_x emissions in these areas. An additional emission benefit of using clean fuels in urban buses is reduction in air toxics and particulate emissions. However, the clean fuel vehicle manufacturers will require significant lead time. In addition, production and distribution infrastructures for some clean fuels would have to be significantly developed in many areas before large-scale urban bus use could occur. Both S. 1630 and S. 1490 call for introduction of an urban bus program from model year 1991 to 1994. However, S. 1630 omits needed flexibility to delay elements of the program by up to 2 years, in contrast to the S. 1490 provisions. This should be added to the S. 1630 program.

Onboard Refueling Vapor Recovery Systems

The Administration proposal and S. 1630 differ on the fundamental issue relating to refueling. While S. 1630 requires Stage II fuel pump controls at service stations in all serious, severe and extreme ozone nonattainment areas, it also mandates that beginning with the 1993 models, "onboard" refueling controls must be installed on all light duty vehicles - a category that includes many light trucks and vans as well as passenger cars.

The Administration believes it is inappropriate to include an onboard mandate because of the unresolved safety issues of those systems and the ability to target Stage II controls to ozone nonattainment areas. Certainly, there is no evidence that both systems are needed to address refueling emissions. Such dual requirements impose unnecessary costs, and should be eliminated in favor of Stage II.

Air Toxic Emission Levels

Many provisions of the mobile source title S. 1630 are intended to both lower air toxic emissions levels and affect ozone nonattainment. I've already discussed two of these provisions - fuel volatility changes and the clean fuel bus program - which are of particular interest to energy.

I will now comment on two provisions of S. 1630 that primarily affect toxic air emissions.

Lead Phasedown

S. 1630 would require EPA to issue regulations that prohibit the manufacturing or selling of motor vehicle engines or nonroad engines that require leaded gasoline. In addition, S. 1630 would prohibit the use of leaded gasoline. S. 1490 has neither provision. Use of leaded gasoline has declined substantially due to present EPA regulation of leaded-gasoline fuel content and because of present emission controls on newer vehicles.

In general, most leaded gasoline is currently produced by small refiners. Thus, any prohibition on leaded gasoline use would affect them primarily. These refiners could modify their operations by adding reforming capacity and/or using oxygenates (such as MTBE) to replace the octane provided by the lead additives. In addition, although leaded gasoline usage is declining naturally, there are many agricultural vehicles which still depend on its availability to operate effectively. This provision of S. 1630 is not necessary to assure continued phasedown of lead to a virtual phaseout and should be deleted.

Diesel Fuel Desulfurization

Both S. 1630 and S. 1490 call for reduced sulfur content and a minimum cetane number (an index of the ignition quality of a fuel) in motor vehicle diesel fuel. S. 1630 requires greater desulfurization of diesel fuels than S. 1490. Currently, diesel fuel must meet an American Society for Testing and Materials (ASTM) minimum cetane number of 40, whereas fuel oil has no cetane number specification. Since fuels which satisfy the ASTM No. 2 diesel requirements generally satisfy the No. 2 fuel oil specification as well, some refiners choose to produce one product which is sold to both markets, rather than incur the cost of segregating the products and blend stocks. The same storage tanks, loading facilities, and pipelines are used for the common product.

Both of these provisions are expected have significant energy implications: diesel fuel desulfurization and lead phasedown in gasoline will result in increased refinery energy consumption and cost due to additional fuel processing.

S. 1490 includes an additional provision for reducing mobile source-related toxic emissions which S. 1630 does not incorporate. This air toxics provision of S. 1490 would require EPA to study the need for the feasibility of controlling toxic air emissions associated with motor vehicles and motor fuels that are unregulated under Title II. I will discuss the value of such a study in the later section that addresses air toxic provisions.

Carbon Dioxide (CO2) Vehicle Standards

S. 1630, in the mobile source Title II provisions, establishes for the first time a standard limiting the amount of CO2 emissions from light duty vehicle exhaust. Since CO2 emissions are directly related to fuel economy, the impact of this provision would be to set average fuel economy standards of new gasoline-powered cars at 33 miles per gallon in 1996 and 40 miles per gallon in 2000. Thus, these standards are equivalent to proposing new, dramatically increased CAFE standards.

The Administration opposes the inclusion of CO2 standards in the Clean Air Act Amendments. It is premature to mandate specific controls to address global warming. International negotiations are underway and should be completed prior to any U.S. action to restrict CO2 emissions. Increased fuel economy requirements raise important non-environmental questions that need to be carefully considered, such as feasibility, cost and the competitiveness of the U.S. auto industry with foreign manufacturers.

Further, the Department's analyses do not support these increased fuel efficiency levels as feasible within these timeframes. I have attached a written statement submitted to the House of Representatives Subcommittee on Energy and Power, Committee on Energy and Commerce on July 13, 1989. The statement provides the Department's conclusions as to the technical and commercial feasibility of various fuel economy levels for model year 1995 cars and light trucks. Because these levels reflect only feasibility and not the other statutory criteria in the Motor Vehicle Information and Cost Savings Act, they should not be mistaken for recommendations for fuel economy standards.

The issue of potential global climate change deserves, and is getting, national and international attention. I believe that both the Administration and this Committee can point with pride to their leadership in developing discussions and building consensus on better understanding the processes and the potential responses to the possibility of accelerated rates of global climate change. However, the Administration does not support actions such as this provision of S. 1630, which is isolated from the global climate change policies by bodies such as the Intergovernmental Panel of Climate Change and by Administration efforts, such as the National Energy Strategy.

II. AIR TOXIC PROVISIONS (TITLE III)

S. 1630 Air Toxic provisions of major concern to energy industries include:

- Control Technology Requirements - Maximum Achievable Control Technology (MACT);
- Residual Risk Limits;
- Source Categories and Exclusions;
- Accidental Releases; and
- Mandatory Air Toxic Regulation of Mobile Sources

I will discuss the provisions in terms of impacts on the oil and gas and the electric utility industries, and on light duty vehicles.

Use of Mandated Studies to Characterize Toxic Emissions

First, however, let me point out a major difference between the two bills. This concerns how energy industries and mobile sources may be much more severely affected by S. 1630 than by S.

1490 without attendant environmental improvement. For both the electric utility industry and mobile sources, S. 1490 would not impose the Maximum Available Control Technologies (MACT) standards until special studies are carried out by the Administration to determine the extent to which existing regulations and authorities, plus the added authorities of other titles of an amended Clean Air Act, would limit toxic air emissions. Further, the study would analyze what environmental and health impacts are associated with toxic emissions from these sources. These studies would propose what, if any, further controls would be appropriate for managing air toxic risks from these sources.

In S. 1490, there is discretion as to how up to 50 percent of the source categories of a toxic pollutant would be treated. S. 1490 would allow EPA greater discretion in defining source categories by applying regulation to the 50 percent of the air toxic sources that pose the least risk. Further, within the 50 percent grouping of source categories that pose the least risk, S. 1490 would allow EPA to determine if a specific source should be regulated under Title III. For example, in the area of oil and gas production, the source category of stripper wells might be studied and it may be determined by EPA that this category, because of remote location of wells and the low emissions levels, should not be subject to MACT.

These two cases of greater flexibility of S. 1490 compared to S. 1630 are clear indications of how both energy and environmental goals should be considered in determining what further controls are needed to limit toxic emissions and their impacts. This flexibility is especially appropriate for source categories where other added emission controls contained in these complex bills are likely to cut the levels of toxic emissions. Because of acid rain provisions for powerplants, and ozone and nitrogen oxide controls for oil and gas production and refining, and for light-duty vehicles, there would be significant reductions of toxic emissions under either S. 1490 or S. 1630 even without the setting of a MACT standard.

We propose that the special study provisions of S. 1490 noted here be added to the S. 1630 bill. The following comments are provided to set forth some more discrete concerns with elements of the bill affecting energy industry segments.

Oil and Gas Industry Concerns

The following is an overview of these provisions with respect to the oil and gas industry:

- Residual Risk Limits: S. 1490 requires that unreasonable risk remaining after technology based standards be further controlled; S. 1630 sets rigid requirements for what level of risk must be reached. S. 1490 is preferable because it states that EPA shall promulgate standards to protect adequately against unreasonable risk, with consideration of cost and other factors. The approach in S. 1630 could result in for air toxics regulation with consequences that could be more adverse than the benefits gained. Further, the residual risk provisions of S. 1630 could result in unattainable emission limits for industries. This is of concern to the oil and gas industry because many facilities are small, remotely located individual emitters of air toxics. S. 1490, on the other hand, provides EPA with the discretion necessary to avoid promulgating rules that could close down segments of industry without assuring significant health risk improvements.

- Source Categories and Exclusions: Regulating virtually all sources of toxic emissions, as currently contemplated under S. 1630, could be a waste of resources and would not provide greater public health protection. I discussed this earlier using the example of stripper wells. S. 1490 allows EPA discretion in defining source categories and in developing regulations; discretion that is essential to avoid costly efforts to regulate sources that are determined not to warrant control. Industries and industry segments should not be required to install costly MACT controls when their emissions are inconsequential to public health. Many oil and gas facilities are small individual emitters that are widely dispersed and far from population centers. Industry estimates of impacts of S. 1630 on such industry segments as stripper wells indicate high costs and the likelihood of shutdown of a substantial number of these energy sources. We believe that any regulation of these facilities should be based on a more exacting study of both economic and environmental impacts and that greater discretion on regulation of smaller sources should be provided the EPA Administrator, as done in S. 1490.

o Accidental releases: These releases are already addressed in the provisions of Title III of the Superfund Amendments and Reauthorization Act (SARA) and under process hazard management provisions of OSHA. Further regulation as part of the Clean Air Act without further data and analysis is not appropriate. S. 1630 would impose costly leak detection requirements. Also of concern is that S. 1630 proposes to establish an independent accidental release investigation board, whose responsibilities would overlap with the activities of EPA and OSHA. S. 1490, on the other hand, would provide EPA capability to investigate accidental releases and allow the Administrator to deal with needed controls consistent with the full context of his authorities.

You also requested I comment on the costs of compliance with S. 1630 for the oil and gas industry and its consumers. Several industry groups have estimated well shutdowns, production losses, costs of MACT, price impacts, etc. These estimates of adverse impacts are significant - several billions of dollars of lost income, lost production, and large price increases for consumers. I have provided a summary of some of these estimates as an attachment to this testimony. The Department is in the process of evaluating these estimates.

Electric Utility Impacts Due to S. 1630

The following discusses the major Air Toxic provisions of S. 1630 affecting electric utilities and, where appropriate, compares them to S. 1490:

- Control Technology Requirements: Powerplants that are already subject to a diversity of required controls for particles and gases. Use of a rigid regulatory regime such as that provided in the air toxics title, may take away much of the flexibility provided to power plants in Title IV with respect to SO2 and NOx emission reductions. This is one of several reasons why we support the study of electric utility emissions and the tailoring of any air toxic regulation to the special circumstances of electric utilities, as needed, as is proposed in S. 1490, before any added regulation to reduce air toxic emissions is promulgated.

- Residual risk limits: We prefer the flexibility of S. 1490 over S. 1630. For example, S. 1490 specifies that EPA shall promulgate standards "to protect adequately" against unreasonable risk with consideration of cost and other factors; S. 1630, on the other hand, proposes use of rigid standards of one in one ten thousand with a goal of one in one million. As with the proposed S. 1490 study of electric utility emissions, I believe that the flexibility of S. 1490 in defining what are the parameters of residual risk will substantially reduce costs.

Further, S. 1490 would require a residual risk determination 7 years (vs. 5) after implementation of technology controls. This more extended period provides sufficient time to monitor actual conditions and to conduct analysis and public rulemaking. This is especially important for an industry that will not have the Phase I acid rain controls fully in place until 1995 and will not finalize the choices of Phase II controls until after 1995. Selection of which controls are implemented to comply with the Acid Rain Title will affect the level of toxic emissions released from the plants.

Regarding your request for our estimates of the costs of compliance with the air toxic provisions, let me conclude by offering a few qualitative statements of costs to the electric utility industry.

- Consumer prices are likely to rise as the industry invests significant monies to control air pollutants.

- Based on the distribution of power plants and populations, it appears that the greatest burden of control costs would be shouldered by consumers in the Northeastern States.

- Installing MACT will be costly, particularly for coal-fired power plants. These controls would be required without any demonstration that such controls are necessary to produce any significant reduction in public health risks. Greater discretion in study, regulation and permitting is needed here. S. 1490 provides such discretion for electric utilities.

- Under the MACT air toxic standards, coal burning utilities, which would have to control for trace amounts of air toxics, would incur substantial added costs. For example, it is estimated that for control of chlorine, added costs to coal-fired powerplants could be on the order of several billion dollars. This could jeopardize the Clean Coal Program and also force utilities to switch to alternative fuels or technologies. Given the other control costs, special studies of options and risks are needed.

This concludes my testimony. Thank you.

ATTACHMENT

Summary of Oil Industry Estimates of S.1630 Cost of Compliance

- Compliance May Result in Increased Shutdown of Stripper and Other Marginal Wells:

  1. The Independent Petroleum Association of America (IPAA) reports that:

     a. 125,000 stripper wells would close [EPA estimates that there are roughly 450,000 stripper wells producing up to 10 barrels//day of crude oil and operating at the maximum feasible rate of production];
     b. roughly 25 percent of existing wells would become uneconomical to operate;
     c. over 4,000 new wells not be drilled; and
     d. roughly 29,000 oil wells are expected to be permanently plugged and abandoned.

  2. API estimates the closing of 175,000 stripper wells producing 2 barrels or less per day.

- Losses in Domestic Production: IPAA reports annual production would decline by 52 million barrels.

- States Severely Affected: IPAA estimates numerical impacts (wells plugged, production lost, and other parameters) on eight selected states. They are (in order of greatest to least impact): Texas, Oklahoma, Kansas, New Mexico, Wyoming, Louisiana, Michigan, and Montana.

- The Residual Risk Provisions are Highly Uncertain but Appear Extremely Costly.

  1. To date, no refiners have said anything about closing, and it is unlikely that any such announcement would be made at this time.

  2. Major concern is that the proposal would require the control of "residual emissions" after having applied MACT to remove most toxic emissions. An analysis performed for API estimates that complying with MACT could cost the production sector and refineries of up to $8.5 billion and $1.3 billion, respectively; however, expanding control to include residual risk could raise costs to $27 billion for the production

sector and $14 billion to refineries. The range in these estimated reflects the uncertainty in defining MACT; thus, the ultimate cost remains unknown.

3. In addition, operating and maintenance (O&M) costs would rise. API estimated that applying MACT could result in O&M costs of $550 million and $175 million, respectively, for the production sector and refineries. If residual risk is controlled, O&M costs rise to $810 million and $340 million, respectively, for the production sector and refineries.

o Effects of Compliance on Consumer Prices:

1. API sources note that "back-of-the-envelope" estimates predict rises for $0.10-0.25/gallon of gasoline. Some producers may absorb some of the cost at first to get a competitive edge (marketing), but their actions can't be predicted.

2. IPAA estimates other costs of the legislation:

   a. upfront capital costs of air toxics legislation on O&G exploration and production will be $8.6 billion;
   b. severance taxes paid to states would decline by $54 million;
   c. royalties paid to state, federal or private landowners would decrease by $125 million; and
   d. roughly 68,000 industry jobs and 88,000 jobs in other sectors of the economy would be lost due to decreased expenditures for goods and services.

The CHAIRMAN. Thank you very much, Ms. Stuntz.

Next, Bill Rosenberg, Assistant Administrator for Air and Radiation of EPA is back with us. Thank you, Bill.

STATEMENT OF WILLIAM G. ROSENBERG, ASSISTANT ADMINISTRATOR, AIR AND RADIATION, ENVIRONMENTAL PROTECTION AGENCY

Mr. ROSENBERG. Thank you, Senator.

We have attempted to coordinate with the Department of Energy and not cover the same areas that Ms. Stuntz covered.

What I would like to refer to first is a handout that I gave the committee this morning called, Cost Comparisons in the Clean Air Act. And if you turn to the first chart on about page 5, it does—which says, annual cost comparison Clean Air Act amendments.

I would like to point out just in a macro view what we see as the essential cost differential between the administration's proposals and, indeed, the proposals that were passed through the House Subcommittee on Environment and Health that Mr. Waxman chairs and the Senate proposal.

In the nonattainment area, the President proposed a $10 billion program. The House upped it to about a $12 billion, essentially by adopting California tailpipe standards in 1993, which the administration is prepared to concur in. The Senate nonattainment provisions raised that $12 billion to $23 billion. The bulk of that is a mandated phase two tailpipe program that we estimate costs $7 billion more than our proposal, but does not get any more environmental benefit than our proposal.

On the acid rain title, looking at the year 2005, you can see that the administration and House proposal which is the same is $4.1 billion and the Senate is $4.5 billion. The principle differential as we discussed yesterday was the NO_x requirements in that bill. Although, we have other concerns.

In the air toxics area, that is where the increase is so great. The original proposal of the administration was $4.7 billion. The House increased it some. But the Senate increased the $4.7 billion to over $14 billion, roughly a $9.5 billion increase.

The CHAIRMAN. Let me interrupt you there. You are talking annual cost. Edison Electric through its consultant, Temple, Baker & Sloan, said annual cost would be $12.7 billion but capital cost would be $59 billion for scrubbers.

Are you including capital cost?

Mr. ROSENBERG. This would be the annual cost of servicing that capital, and so this does not relate to the investment, per se, but just what the annual operating cost would be. Edison Electric may have just been focusing on the electric utility side.

This is for all air toxics provisions, and I would suspect that they have a higher estimate of the electric side than we. There is a great uncertainty here. That is one of the big issues. The uncertainty goes to enormous cost for very modest benefits, in our judgment, and we will show you some data in a moment.

I will not go through the rest of this report which was handed out yesterday, but it does have more detail to explain these numbers. The President's position is that essentially what we had proposed and what the House had approved should be the appropriate level of cost. It is adding $20 billion to $22 billion to the already $30 billion. It achieves the environmental benefits needed to reach attainment in the various areas to deal with the acid rain problem and to very substantially reduce the air toxics issues.

To go beyond that which principally relates in the air toxics area for mandatory actions rather than discretionary actions on the part of the Administrator who could in our bill consider cost and economic implications as well as health implications to deal with the small part that remains is not sensible for the economy.

I will walk through three charts, if I might, to cover some detail here. In the nonattainment area, the principal differences are in the stationary source area, our definition of a major source subject to new source review.

The President's bill retains the 100-ton standard. The Environmental Committee would lower that standard to as little as 25 tons or 10 tons per year. That would capture many more small sources. We would estimate up to 10,000 smaller sources, small businesses in the country, perhaps things, for example, such as university power plants, bulk gasoline plants, commercial bakeries of substantial size, some of the pumping stations on our natural gas pipelines, larger dry cleaners and auto paint shops, airports, city recycling and incinerator operators, and the list goes on.

It essentially mandates as a matter of Federal law that these smaller sources would be subject to the same rules that larger refineries or utilities would be subject to in terms of meeting Federal technology standards, meeting Federal permitting requirements, and paying permitting fees. We believe that the appropriate way to handle that is at the local level where the requirement for achieving attainment is established by Federal law but there is some flexibility at the local level to decide which of the smaller sources have to meet tougher environmental requirements.

We oppose the mandatory changes in the environmental bill. At the same time, we support the provision for making annual improvements of 3 percent a year. So there is a progress requirement in the President's proposal as there is in the Environmental and Public Works Committee. We would leave the implementation of that to the local level so that they could assure that economic growth and dislocation are taken into account.

Although we do not have detailed information on oil and gas facilities, per se, examination of available sources show that reducing the cutoff from 100 tons to 25 tons or 10 tons per year increases the total number of sources affected by permitting fees and reasonable available control technology requirements by three- or fourfold.

It is certain that the number of smaller utilities and particularly oil and gas production facilities affected by these provisions could be significantly greater under the Senate version than under the administration's bill. Even natural gas pumping stations could become major sources under the reduced cutoffs.

Also, we do not project environmental benefits comparable to the cost that these provisions would incur on the smaller facilities.

Further, the Environmental Committee's provisions to eliminate netting and increased offset requirements would likely make it harder to expand existing oil and gas production. They would also make new construction projects in nonattainment areas more difficult.

There is an anomaly that we have heard in testimony from ARCO before the other committee which said that they are prepared to develop reformulated gasoline in their refineries in California, but they are not sure under the Senate bill that they would be able to make the modifications in the refinery to produce the reformulated gasoline. That would reduce the emissions dramatically in cars.

The CHAIRMAN. Can you tell us how that anti-netting provision would affect refineries?

Mr. ROSENBERG. It would mean that if there was a modification that added emissions under current law, as long as the plant reduced emissions somewhere else with no net increase, that modification could be achieved without an offset outside of the plant. Without the netting provision, if there is a major modification such as one that would be required to make reformulated gasoline, for example, then the company would have to find outside of the plant an offset reduction independent of what it did within the plant.

We believe that that would retard the very goals that we are seeking in making the gasolines cleaner and reducing overall VOC emissions below where they are now. We also think it would make it much more expensive to operate a business in an environmentally sound way.

The CHAIRMAN. While we are on the subject and not to get into the questions now, to go to reformulated gasoline you would also, in reconfiguring the plant, have to pass muster under the permitting process anew, would you not?

Mr. ROSENBERG. That is true. Of course, the procedure would be no new permit for additional emissions required.

Speaking of permits, the permitting fees required under the Senate bill are much, much higher than those required by the administration bill. The administration bill requires fees equivalent to $25 per ton for sources required to have a permit, but there is a cap of $100,000 per facility.

The Environmental Committee includes much higher fees, $90 per ton with no cap, and there is also a fee of $2 per car in ozone nonattainment areas.

The administration's fee provision raises an estimated $310 million. The Environmental Committee's fees would raise a whopping $1.3 billion.

The administration's proposal is a fee to cover the cost of the permitting program. The amount of funding it would raise is about consistent with the estimates we received from State and local governments and our own estimates as to what the permitting program would require. The Environmental Committee raised about three times the amount of the cost of operating the permit program. Especially with the $2 per car fee, it seems more like a tax increase to the administration.

I will not go through all of the other requirements that are different other than to mention them. Relating to transport area requirements, a requirement that consumer and commercial products be regulated.

There is a different approach to sanctions in the administration bill. There is a discretionary sanctions provision rather than mandatory sanctions, and the Senate bill requires a 4 percent annual improvement versus 3 percent, which could be very, very close.

Turning to air toxics, I would like to refer just as a background point that motor vehicles are responsible for a majority of the air toxics problem. The Air Toxics Bill before the Senate does not deal with the motor vehicle principally but deals with the large point sources and small area sources which are about 20 to 40 percent of the problem.

The principal differences between the administration's proposal and the Senate Committee's proposal are really four. One is a mandatory MACT for all source categories. Second is how we handle residual risk. Third is accidental release provisions. Fourth are emissions from utilities. I will cover each of these.

Like nonattainment, there are certain structural similarities between the administration's air toxic provisions and those of the Environment and Public Works Committee. We both agree that the approach in current law needs to be replaced with a two-step approach. The first step would put maximum achievable control technology, MACT, on sources that present the highest risk. The second would evaluate the remaining risk and determine whether additional controls are needed.

We have generally a comparable approach in the first phase. Relatively, the administration's cost is $3.1 billion in the first phase, and the Senate's approach is $4.1 billion. That really reflects a difference principally in the way in which we handle the utility sector.

The first phase deals with 8 percent of the potential risk problem, and it would require industries from the chemical, tire, glass, steel, petroleum and other industries to put on the maximum achievable control technology that is currently known. It would reduce, in our judgment, approximately 80 percent of the potential risk to the population coming from those sources.

The big dispute comes in the second phase where the administration proposes to evaluate the risks that are remaining and then, in a reasoned judgment way using issues relating to health, considering health risks, considering whether a plant would have to close down, economic issues, make additional improvements. We estimate that that would cost the society approximately $1.5 billion to get at the 20 percent risk remaining.

The Senate version, on the other hand, would require that the health risk be reduced below one times ten to the minus four without consideration of cost, and we estimate that the Senate version would for this incremental amount add a $6 billion price tag to those regulations. That is really the principal difference between the administration's and Senate's proposals on air toxics.

As shown on the chart, the incremental environmental benefits under the Senate bill would be minimal. We project that we will address approximately 80 percent of the potential risk reduction from stationary point and area sources in the first phase of the program when MACT is applied. We project our costs as being $1 billion per year less than that of the Environmental Committee proposal.

I should note that the Senate proposal would achieve slightly more than an 80 percent reduction, although we do not know how much in the first phase, and that $6 billion in the second phase would achieve slightly less than a 20 percent reduction.

In the second phase the cost differential becomes very high. We estimate, as I pointed out, these costs. Although the extent to which this provision would specifically affect oil and gas production or the utility industry cannot be determined at this time, we believe the residual risk requirements of the Environmental Committee bill could potentially shut down many facilities and result in these higher costs to the economy.

Specifically relating to the electric utilities, the administration's proposal requires EPA to conduct a study of the potential health risk, if any, due to air toxic emissions from utilities prior to imposing any air toxics regulatory requirements. The reason for this study is twofold.

First, over the next decade the utility industry will be faced with substantial compliance costs associated with the implementation of acid rain controls.

Second, there is insufficient information at this time to suggest that emissions of air toxics in the vicinity of utilities pose substantial significant health risks. The study would provide a much needed opportunity to evaluate any potential health risks associated with these utility emissions.

The Environmental Committee took a different approach. It requires utilities to comply with air toxic regulation for all pollutants which they emit except chlorine compounds. Not only would these regulations overlap with regulations under the acid rain provisions, but they would set up a two-track regulatory system for utilities which would consider chlorine emissions separately from other air toxics. This could result in one set of controls being applied for nonchlorine compounds and three years later another set of controls for the chlorine controls and then later another set of controls for acid rain controls.

The administration believes it is far more sensible to study the potential health risks from utility air toxic emissions and to consider how to implement those provisions in the context of implementing the acid rain control provisions before imposing any mandatory requirements.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Mr. Rosenberg.

Next we will hear from David Doniger, who is senior attorney with the Natural Resources Defense Council on behalf of the National Clean Air Coalition.

STATEMENT OF DAVID DONIGER, SENIOR ATTORNEY, NATURAL RESOURCES DEFENSE COUNCIL

Mr. DONIGER. Thank you, Mr. Chairman.

And I am going to begin with an apology that, it is going to be necessary for me to leave about 11, because Congressman Waxman is holding a hearing on ozone depletion at the same time as this hearing. And I feel I am being torn between being two places at once and so my apologies.

I would like to focus on the air toxics provisions. We are very strongly in support of the S. 1630 air toxics provisions, instead of the administration's. The S. 1630, we believe, fulfills—moves to fulfill a promise of health protection that Congress made first 20 years ago. And to redress effectively the staggering toll of death and illness and environmental devastation wrought by toxic pollutants.

In a move that we think would deny the public its long sought protection from toxics, industry groups and the administration are seeking to strip out the central and vital feature of these amendments, standards for actually protecting public health from cancer-causing air pollutants.

S. 1630 already embodies a compromise that gives great weight, indeed too much weight, in our view, to industry concerns. The bill allows facilities that emit cancer-causing air pollutants up to 15 to 23 years before they are subject to any health-based standard at all. That is not until 2005 to 2013. And at that point, these facilities have to reduce the chance of getting cancer for the people most exposed to their emissions to one chance in 10,000.

While a further standard of one chance in 1 million is also established, the bill allows essentially permanent extensions to sources that show they cannot meet this standard.

Well, now, the Clean Air Working Group and the Business Roundtable can be heard complaining about the alleged difficulty in cost of meeting these health protection standards, and they base their attack—as has the administration—on grossly exaggerated cost estimates that seem to be governed in the toxics area by two principles: hyperbole and fear.

They have deliberately misinterpreted the bill—the industry has—so as to ignore both the lead time the bill provides for getting to one in 10,000 and the extensions available from the one in 1 million standard. They have also based their gloomy predictions—and this is, in this they are joined by the administration—on an assumption that no knowledgeable or successful businessman would ever make. That companies working to comply with S. 1630's health standards in 2005 or later would be limited to using the technology available today, and there would be no advances in that technology.

The overheated attack on health standards is all the more curious in light of the quite different policies of a number of leading companies. At least three major companies, Monsanto, Union Carbide and DuPont have publicly committed to the objective of eliminating their cancer-causing emissions. Indeed Monsanto's commitment is to eliminate all its toxic air emissions, carcinogens and noncarcinogens.

If these companies have adopted the policy of eliminating cancer causing emissions, how credible can be the complaints of trade associations and lobbying groups against the much easier task of meeting S. 1630's less ambitious interim health standards? In fact, if the policy of eliminating cancer-causing emissions is good enough for these major companies, why should it not be also the policy of the U.S. Congress as well?

Now, I will return to the exaggerated cost estimates in a minute. But I want to briefly describe a couple of features of this amendment. And one that I would like to focus on, given this committee's interest in the effects on the energy industry, is an example of how this legislation might have avoided not only a public health tragedy, but a major disruption in energy markets, if it had been enacted a couple of years ago.

Now, I am referring to the explosion on the day before Christmas, barely a month ago, of the Exxon heating refinery in Baton Rouge. Two people were killed. A fire burned for 15 hours. The refinery was knocked out of service at a time when—to paraphrase the headline of a newspaper story the day before the accident—oil refineries were already working on all cylinders to supply the nation with heating oil in the midst of a severe cold spell. In the aftermath of the explosion, heating oil prices soared across the nation in significant part because of the loss of Exxon's capacity. In some places heating oil prices doubled in two weeks.

The Exxon explosion was only one of more than 11,000 chemical accidents that occurred in the 1980s according to incomplete statistics compiled by EPA. More than 300 people died. More than 11,000 others were injured in these accidents. More than a half million people were forced to evacuate homes, schools, and workplaces. There were losses of billions of dollars in property damage and lost productive capacity.

The toxic pollutant provisions of S. 1630 include the nation's first meaningful program to prevent chemical accidents. It establishes a chemical safety board modeled on the National Transportation Safety Board to investigate why accidents like Exxon's happen, and what is needed both in industrial voluntary reform and in governmental regulation to keep accidents like that from happening again.

I suggest that if this law were enacted before the Exxon accident, the day before Christmas, that accident might have been averted. Lives could have been saved, and billions of dollars in economic losses, because of the shortage of heating oil would have been avoided.

You know, a lot of the focus of the discussion has been on the routine emissions of air toxics from facilities which are operating normally on a daily basis: industrial facilities, smaller sources and motor vehicles. The EPA has estimated that just a subset of the cancer-causing pollutants from these sources are responsible for as many as 2,700 fatal cancers each year. Over our lifetime that would mean almost 200,000 preventable fatal cancers due to air toxics.

In addition to these cancer deaths, there would be a comparable number of nonfatal cancers imposing enormous suffering and staggering costs, even on those persons who are cured. The EPA estimates about half this toll is due to vehicle emissions with the other half divided between large industrial facilities and smaller ones.

These cancer risks are not spread evenly among us. And this is where the health standards of the bill, the residual risk standards as they are sometimes called, have the greatest importance. Some people living near some facilities now, for example one in Texas, are exposed to greater than one in 10 chance over their lifetime of getting cancer from a facility that emits butadiene in Port Neches, Texas.

One chance in 55 is the risk for some of the people exposed to coke oven emissions. One chance in 300 of getting cancer for multiple pollutants in large areas of Chicago. The National Clean Air Coalition believes that all Americans, especially people who are most heavily exposed, are entitled to protection from airborne cancer. Now, deaths and illnesses from other toxic pollutant-related illnesses have not been quantified, but they are to be considered too.

The bill provides us two steps as has been described: MACT in the first step, followed by a health-based second step called residual risk standards sometimes. Now the difference between the administration bill and S. 1630 is really important here, because the administration bill does not want health standards. It wants a cost benefit approach. And that would mean that people who live in the areas of the highest exposure to these cancer-causing chemicals could be left in those islands of risk with nothing but a pat on the back, because the administration judged that the cost and benefits of protecting their lives from these disproportionate cancer risks did not add up. We think that is unacceptable.

Now, the problem with the cost estimates—and I will be brief here—is fundamentally two things. First of all, the industry assessment is misrepresenting what the bill provides. Industry assessment is assuming that there would be large costs for meeting one in 100,000, or one in 1 million standards; $62 billion for a one in 1 million standard; $25 billion for a one in 100,000 standards.

And they are ignoring the very important fact, that S. 1630 does not require any source which has difficulty meeting standards like that to actually meet that standard. If you cannot meet it, you get an extension. For one in 10,000 that is not true. For one in 10,000 there is, finally after 15 to 23 years, a real deadline. But for standards tougher than that, those who represent the bill as saying that those standards have to be met despite the difficulty sources would have it are wrong. That is not what the bill provides. Perhaps it should provide that, but it is not what the bill provides.

And so these inflated cost estimates associated with those standards are just not responding to the bill in front of the Senate.

The second problem—and focusing in on the administration's estimate of approximately $6 billion for the one in 10,000 standard—is that it is based, as I said before, on an assumption that no knowledgeable or successful businessman would ever make. Namely, that the technology you have today is all you will have 15 years from now.

Now, we have examples in the history of the Clean Air Act of how this technology forcing policy of setting standards with lead time works to protect public health and develop technology. That is the way it happened with the auto emission controls. In 1970 the auto industry claimed it could not meet the standards then under consideration. Congress set a deadline, and the industry developed the catalytic converter.

Now, in 1990, the auto industry and the oil industries are facing real pressure for clean air progress once again. And once again they are beginning to say they can do things that they previously claimed they could not do: reformulate fuels and even offer prototypes of serious electric cars.

Look at the story of the CFCs. Before the governmental commitment to controlling the destroyers of the ozone layer, industry claimed that they were unique and irreplaceable chemicals. Now with the expectation of a total phaseout by the end of the century or before, the CFCs are being rapidly replaced.

Just two years ago the electronics industry contended it literally could not survive without a solvent known as CFC-113. Now the electronics industry is literally awash in substitute solvents. Water-based compounds, alcohols, even compounds made from orange peels in Florida. And there are companies that are developing processes for making electronics that need no solvents at all, and they will be in place in 1991. Northern Telecom.

The same story can be told for technologies as diverse as sulfur scrubbers and solvent-free paints and coatings. Where the regulatory environment provides the incentives, these technologies can be developed, if there is lead time. And this bill has 15 to 23 years of lead time.

So, we think that it is totally unreasonable to make the assumption that companies which do not currently have available to them, or say they do not, the technology to meet these standards, that they still cannot develop that technology and install it at an affordable cost over 15 to 23 years.

And if it should turn out that a specific company, or a specific industry has difficulty, then the Congress can do what is showed it was able to do for the auto industry, namely, adjust the timetable. When the time draws near, and you have had a fair trial, and you can evaluate what has been done.

Let me close with one word about utilities. The claim that all utilities would have to use scrubbers is based on an assumption that the chlorine from these utilities comes out of the stack in a form that is on the list of toxic pollutants. There are 191 toxic pollutants. Several of them are chlorinated compounds, the principle one is hydrochloric acid. We do not know for sure that the chlorine from the utilities comes from in the form of hydrochloric acid. If it does not, it would not be covered.

The second thing is, if, as the utilities are claiming, there is no health risk from this emission, then the bill includes another provision which the administration and the utilities are ignoring, which is one that says that the EPA can set a health standard which is at whatever level necessary to protect health. And if that happens to be less stringent than the MACT, then the MACT standard does not have to be applied.

In other words, if it does not take scrubbers, or even sorbent injection, or any technology at all to protect public health from the chlorinated compounds that come from these utilities, then no standard at all would be required under the bill.

We do not think that it is necessary to have a special exemption or delay in study provision for utilities, since the flexibilities in S. 1630 to accommodate the arguments that are being made. And it is not our intention to have a universal scrubber requirement imposed through the toxics. And we do not believe that the bill would require that. But if there are health hazards, they should be controlled with whatever it takes to protect the health of the people in the community around utilities, no less than around refineries or any other source of pollution in this country.

Thank you.

[The prepared statement of Mr. Doniger follows:]

Testimony of David D. Doniger
Senior Attorney, Natural Resources Defense Council
on behalf of the National Clean Air Coalition
before the Senate Committee on Energy and Natural Resources
January 25, 1990

Mr. Chairman, thank you for the opportunity to testify today, on behalf of the National Clean Air Coalition, on the toxic air pollutants provisions of the Clean Air Act amendments now before the Senate, S.1630. Moving to fulfill the promise of health protection Congress first made 20 years ago, these amendments represent the first effective attack on the staggering toll of death, illness, and environmental devastation wrought by toxic pollutants.

In a move that would deny the public its long-sought protection from air toxics, industry groups are seeking to strip out the central and vital feature of these amendments -- the standards for protecting public health from cancer-causing air pollutants. As described below, S.1630 already embodies a compromise that gives great weight -- indeed, too much weight, in our view -- to industry's concerns: The bill allows facilities that emit cancer-causing air pollutants up to 15 to 23 years before they are subject to any health-based standard -- in other words, not until 2005-2013. At that point, these facilities have to reduce the chance of getting cancer, for the people most exposed to their emissions, to one chance in 10,000. While a further standard of one chance in 1,000,000 is also established, the bill allows essentially permanent extensions to sources which show that they cannot meet this standard.

The industry chorus, led by the Clean Air Working Group and the Business Roundtable, can now be heard complaining about the alleged difficulty and cost of meeting these health protection standards. They have based their attack on grossly exaggerated cost estimates that appear to be governed by two principles: hyperbole and fear. They have deliberately misinterpreted the bill so as to ignore both the leadtime the bill provides for getting to the 1-in-10,000 standard, and the extensions available from the 1-in-1,000,000 standard. They have also based their gloomy predictions on an assumption that no knowledgeable or successful businessman would ever make: That companies working to comply with S.1630's health standards in 2005 or later will be limited to the technology available today.

The overheated attack on the health standards is all the more curious in light of the quite different policies of a number of leading companies. At least three major companies -- Monsanto, Union Carbide, and DuPont -- have publicly committed to the objective of eliminating their cancer-causing emissions. Indeed, Monsanto's commitment is to eliminate all its toxic air emissions. If these companies have adopted the policy of eliminating cancer-causing emissions, how credible are the complaints of trade associations and lobbying groups against the much easier task of meeting S.1630's less ambitious health standards?

In fact, if the policy of eliminating cancer-causing emissions is good enough for these companies, why should it not be the policy of the United States Congress as well?

I will return to the industry's exaggerated cost claims in a few minutes, but first I want to briefly describe the health and environmental damages these toxic air pollutant amendments address.

Industrial Accident Prevention

Given this Committee's focus on the effects of clean air legislation on the energy industry, let me start by giving you a recent example of how this legislation might have avoided not only a public health tragedy, but also a major disruption in energy markets.

I am referring to the explosion, the day before Christmas barely a month ago, of the Exxon heating oil refinery in Baton Rouge, Louisiana. Two people were killed. A fire burned for 15 hours. The refinery was knocked out of service at a time when, to paraphrase the headline of one newspaper story the day before the accident, oil refineries were already "working on all cylinders" to supply the nation with heating oil in the midst of a severe cold spell. In the aftermath of the explosion, heating oil prices soared across the nation, in significant measure because of the loss of Exxon's capacity. In some regions, heating oil prices doubled in two weeks. (Several news articles on the accident and its economic consequences are attached to this testimony.)

The Exxon explosion was only one of more than 11,000 chemical accidents that occurred in the 1980s, according to incomplete statistics compiled by the Environmental Protection Agency. More than 300 people died, and more than 11,000 others were injured, in these accidents. More than a half-million people were forced to evacuate homes, schools, and workplaces. There were losses of billions of dollars in property damage and lost productive capacity.

The toxic pollutant provisions of S.1630 (Title III) include the nation's first meaningful program to prevent chemical accidents. The bill establishes a Chemical Safety Board, modelled on the National Transportation Safety Board, to investigate why accidents like Exxon's occurred and what is needed, both in voluntary industrial reform and in government regulation, to keep those accidents from happening again. The bill requires companies that handle large amounts of especially dangerous materials to perform and make public "hazard assessments" examining the potential for accidents-waiting-to-happen. In short, were this law enacted before the Exxon accident, it might have been averted. Lives could have been saved, and billions of dollars in economic losses would have been avoided.

"Routine" Air Toxics

Title III of S.1630 also addresses what have come to be called "routine" releases of toxic pollutants -- the emissions of cancer-causing pollutants and other dangerous substances on a daily basis as part of the normal operations of industrial facilities, smaller sources, and motor vehicles. The Environmental Protection Agency has estimated that just a sub-set of the cancer-causing pollutants are responsible for as many as 2700 fatal cancer each year. Over our lifetimes, that could mean almost 200,000 preventable cancer deaths due to air toxics. In addition to these cancer deaths, there would be a comparable number of non-fatal cancers, imposing enormous suffering and staggering costs even on those persons who are cured. EPA estimates that about half the cancer toll is due to vehicle emissions, with the other half divided between large industrial facilities and smaller industrial and commercial operations.

These cancer risks are not spread evenly among us. To the contrary, persons living near certain industrial facilities are exposed to incredibly high lifetime cancer risks: Greater than one chance in 10 for the most exposed persons living near a Texaco facility in Port Neches, Texas, that emits butadiene. One chance in 55 for the persons most exposed to coke oven emissions. One chance in 300, from multiple pollutants, for areas of Chicago. The National Clean Air Coalition believes that all Americans, especially the people who are most heavily exposed, are entitled to protection from airborne cancer.

Deaths and illnesses due to other toxic pollutant-related diseases have not been quantified. But many of the toxic air pollutants slated for regulation under S.1630 are known or suspected causes of neurological, reproductive, and other disorders. Some can cause illness or even death due to acute exposures that can occur as a result of normal operations, let alone accidents.

Title III of S.1630 provides for two rounds of standards for major industrial emitters of some 190 toxic air pollutants: a technology-based first step (called "maximum available control technology"), followed by a health-based second step (sometimes also called "residual risk" standards) targeted where the MACT standards fail to protect public health.

For non-carcinogens -- pollutants that are believed to have a threshold level of exposure below which there is no harm -- the health standards remain under the test of the current Clean Air Act: They must protect public health with "an ample margin of safety." For carcinogens -- pollutants that can be deadly at any level of exposure -- the bill creates two health standards: one that protects the most exposed persons to a level of one chance in 10,000 of getting cancer, and the other to a level of one chance in 1,000,000. Only the 1-in-10,000 standard has a firm deadline: 15-23 years from enactment, taking into account the availability of a five year extension for sources that need it. As noted above, compliance with the 1-in-1,000,000 standard can be extended indefinitely if the necessary controls are not available. We expect most sources will be able to meet this standard, however, with technology that is available today or will be developed over the next two decades.

In addition to Title III, Title II of the bill combats toxic emissions from cars, trucks, and buses. In addition to their contribution to ozone smog, the EPA estimates that half of the air toxics-related cancer death toll in the U.S. is due to motor vehicle emissions. The National Clean Air Coalition strongly supports the bill's two rounds of auto emission standards are provides for two rounds of tailpipe emission reductions. These reductions are essential not only to fight urban ozone smog, but also to cut the toll of cancer due to vehicle emissions.

Contamination of the Great Lakes

In addition to these health effects, toxic air pollutants cause serious environmental damage. The Great Lakes and many other water bodies are heavily contaminated with persistent organic chemicals and heavy metals. For Lake Superior, more than 90 percent of some of the most dangerous pollutants (PCBs, lead, benzo[a]pyrene) entering the lake are coming from the air. According to the U.S.-Canada International Joint Commission, almost 1.2 million pounds of lead are falling into Lake Michigan each year, 99.5 percent from the air.

Once in the water, toxic chemicals are taken up by living organisms in ever more concentrated amounts higher up the food chain. To illustrate, it has been calculated that a single one-pound serving of fish contaminated with five parts per billion of PCBs contains as much PCBs as a person would ingest by drinking Great Lakes water for 1000 years. Every state in the Great Lakes region has issued health advisories concerning consumption of contaminated fish, and in some cases, waterfowl. Serious ill effects are already seen in fish and waterfowl themselves, ranging from cancer among fish species to reproductive and developmental disorders among birds.

S.1630 addresses the hazards to the Great Lakes by requiring pollution reductions from seven specific pollutants. It also directs EPA, when setting public health standards in the second stage of the program, to protect important environmental values as well.

National Clean Air Coalition Support for S.1630

From our point of view, S.1630's toxic pollutant provisions are far from perfect. They take too long -- up to 23 years -- to provide health-based protection to the American public. And from our point of view, the 1-in-10,000 standard for carcinogens -- the only standard with a real deadline -- represents an inadequate level of protection from deadly cancer-causing pollutants. Nonetheless, these air toxics provisions are a major step forward, and are part of a sensible overall program to clean up our polluted cities, curb acid rain, protect the ozone layer, and begin to move on climate change. The National Clean Air Coalition will work for amendments to improve S.1630 -- some of which my colleagues discussed in yesterday's hearing -- and for the bill's final enactment.

The Industry Attack on the Health Standards

Now let me turn to the recent industry attacks on S.1630's health standards for toxic air pollutants. In an effort to scare members of the Senate into stripping out the health standards in Title III, the Business Roundtable has produced a grossly exaggerated cost estimate for those standards. The Clean Air Working Group is now busily circulating the most outrageous of the Roundtable's numbers through inflammatory advertisements.

First, the Roundtable's study rests on a clear misrepresentation of the bill. The study's highest cost estimates are based on the incorrect assumption that the bill requires sources of carcinogens to meet the 1-in-1,000,000 standard at a time certain. This is not the case. While we expect many sources in fact will meet that standard, sources that genuinely cannot meet the standard are entitled to postpone compliance indefinitely. The only binding standard is 1-in-10,000, and only in 15-23 years.

As a result, the $62 billion cost estimate for 1-in-1,000,000 standards is nothing but a straw man. So is the so-called "Best Estimate" of $25 billion for a 1-in-100,000 standards. These hyperinflated estimates have nothing to do with the bill actually before the Senate.

Second, the study's predictions of the feasibility and cost of meeting the cancer risk standards are based on an assumption that no knowledgeable or successful businessman would make: That companies working to comply with the health standards 15 years from now will be limited to the technology available today.

Any sound businessman knows better than to make such an assumption. Over the next 10 years, economic opportunities and challenges alone will bring forth major changes in the process and pollution control technologies for the industries affected by this bill.

When the right signals and incentives are given by government, there is every reason to believe that major advances can be made to control pollution. That's the theory of "technology-forcing," and the Clean Air Act shows that it works. Look at the development of automobile emission controls. In 1970, the auto industry claimed it could not meet the emission standards then under consideration. But Congress set a deadline, and the industry developed the catalytic converter. Now in 1990, the auto industry and oil industries are sensing real pressure for clean air progress again from Congress and the states, especially California. Once again, the industries are doing things they claimed they couldn't do: reformulating fuels, even offering the prototypes of serious electric cars.

Look at the story of the CFCs. Before the governmental commitment to controlling these destroyers of the ozone layer, industry claimed they were unique and irreplaceable. Now, with the expectation of a total phase-out by the end of the century or before, CFCs are rapidly being replaced. Just two years ago, for example, the electronics industry contended it literally could survive without a solvent known as CFC-113. Now the electronics industry is literally awash in substitute solvents: water-based compounds, alcohols, terpenes made from orange peels. They are even adopting pollution-free production processes that require no solvents at all.

The same story can be told for technologies as diverse as sulfur scrubbers and solvent-free paints and coatings. Where the regulatory environment provided the incentives, these technologies were successfully developed, despite early protestations of impossibility.

The reason more of these technologies are not yet available for air toxics is that the hazardous air pollutant program of the current Clean Air Act, as administered by EPA, has been utterly devoid of any technology-forcing impetus. In short, if there are industries that do not yet have the necessary technology available on the shelf to meet a 1-in-10,000 standard today, it is because they have never felt any significant regulatory incentives to develop that technology.

The fact is that within the lead time allowed by S.1630, there is room for the same sorts of technical progress in all the industries affected by the health standards of the bill. And should any industry make a good faith effort to develop the necessary controls, but still face either technological or economic obstacles to compliance as the deadline draws near, that is not the end of the matter. Congress is perfectly capable of evaluating the level of effort made by that industry and the progress achieved, and deciding whether to grant an extension of time.

One thing we can be sure of, however: If the health standards are stripped out, or if the already generous deadline is eliminated, then failure is assured. There will be no technology-forcing effect to the new law without these standards and deadlines. There will be no effort to develop better or cheaper pollution control equipment or process changes.

There are other examples of gross exaggeration in the Business Roundtable report. For instance, the report summarizes an American Petroleum Institute study which assumes that control equipment will have to be ripped out and replaced every five years, because of the bill's provision for a five-year permit review. This is utter nonsense. Yet on the basis of this assumption, API jacked up its cost estimate by $4.4 billion.

The Roundtable report also cites a study for the Chemical Manufacturers Association which assumed the need to control more than 30 chemicals that simply are not on the list slated for standards under S.1630. The CMA study also calculated risks and control costs on the basis of old emissions estimates that the CMA normally criticizes as far too high.

The Administration's latest cost figures on the air toxics health standards share the same major defect as the industry studies: The assumption of no new technology development over the next 15 years. The Administration analysis assumes costs of $6 billion in 2003 -- two years before any source is required to meet the 1-in-10,000 standard -- from the supposed inability of some facilities to meet this level. In other words, the

Administration assumes that none of the industries that are said to be currently unable to meet a 1-in-10,000 standard will succeed in finding the necessary control measures, even with more than a decade of lead time. This simply is not a credible position.

Utilities and Air Toxics

Some utility lobbyists are claiming that because of the chlorine in their fuel, the air toxics provisions will require all utility boilers to install scrubbers, not just those which choose to do so for acid rain reasons. This is not a reasonable interpretation of the facts or of the provisions in S.1630.

In the first place, only certain chlorine compounds are on the list of hazardous air pollutants under S.1630 -- principally hydrochloric acid. Other forms of chlorine -- e.g., chloride salts -- are not on the list and are not regulated under the bill. It remains to be determined whether the chlorine emissions from utility boilers come in a listed form.

In the second place, the bill already allows sources to avoid even the first-step technology-based controls (MACT) if their emissions are already below the level necessary to protect public health. If, as the utility industry is apparently claiming, their chlorine emissions are not causing any health harm, then they will not need to add any pollution controls.

On the other hand, if their chlorine levels do pose health hazards in the surrounding communities, then there is every reason to control those emissions. It is difficult to imagine that many utility sources would need to go as far as scrubbing, however, even in this event. Control techniques such as sorbent injection probably would suffice to reduce chlorine levels below harmful levels, at one-tenth the cost of scrubbers.

Consequently, the National Clean Air Coalition sees no need for and would oppose any special exemption or delay-and-study provision for utility boilers.

Conclusion

To sum up, the National Clean Air Coalition supports the air toxics provisions of S.1630 in order to address the serious public health and environmental risks from these dangerous, unregulated pollutants. We reject the hyperbole and fear-mongering of the Business Roundtable's cost estimates. We see no disproportionate impacts from these amendments on energy-related industries. We urge you to oppose any weakening changes to Title III, and we urge you to lend your support to S.1630.

I would be happy to answer your questions.

Newspaper Articles on:

The Exxon Refinery Explosion in Baton Rouge

Another Case For Prevention

Plants work on all cylinders to get heating oil to nation

TIMES-PICAYUNE 23 DEC 1989 PAGE C-2

By MARY JUDICE
Energy editor

Area oil refineries are running full speed ahead to keep heating oil flowing to areas of the nation frozen by the arctic chill.

Don Kuenzli, operations manager at the BP Oil refinery at Alliance, said extra operating and maintenance workers are on duty and the plant units have been protected as much as possible.

All units were operating at midday Friday with only minor problems, Kuenzli said. He said the plant is running at a maximum capacity of 220,000 barrels of crude oil a day, which yields between 70,000 and 75,000 barrels of heating or furnace oil, and the plant has been producing at this rate for the past couple of weeks.

Exxon had winterized its Baton Rouge refinery for cold weather. Spokesman Dave Gardner said operators were monitoring instrument lines to make sure they did not build up moisture and clog with ice. He said heating oil output had been increased as part of normal winter operations.

Heating oil output will increase by 18,000 barrels a day today at the Citgo refinery at Lake Charles, where a fire damaged a unit last week. Citgo spokesman Kent Young said Citgo plans to increase its heating oil output to more than 30,000 barrels a day when all units are running.

Printed the day before the refinery accident.

Impact of Refinery Fire on Heating Costs

By RANDALL ROTHENBERG

An explosion and fire that damaged parts of a huge Exxon Corporation oil refinery in Louisiana on Sunday could raise heating bills for consumers at least temporarily, oil industry executives and analysts said yesterday.

Even before the fire ignited several storage tanks, these experts said, bitterly cold weather in much of the country had begun to strain heating oil supplies and prices rose to unusually high levels.

The explosion at 1:10 P.M. Sunday killed one man at the Baton Rouge refinery, the second largest in the United States. It ignited tanks containing 3.6 million gallons of heating oil and about 882,000 gallons of lubricating oil. The fire was extinguished more than 15 hours later, at about 5 A.M. yesterday.

The manager of the plant, Ed Gafante, told The Associated Press that a release of gas might have led to the explosion but that the cause remained under investigation.

Exxon officials were still trying yesterday afternoon to determine the extent of the damage. "The processing units at Baton Rouge appear to be undamaged," an Exxon spokesman in Houston said. "The accident is in the storage area."

Nevertheless, industry experts said that because the nation's heating oil supplies were already under severe pressure because of the month-long cold spell that has chilled much of the United States, the slightest disruption was almost certain to raise prices.

William L. Randol, a senior analyst with the First Boston Corporation, predicted that the price of heating oil futures would "skyrocket."

John H. Lichtblau, the president of the Petroleum Industry Research Foundation, said: "Because of the long and extreme cold spell, a tight heating oil market existed at the time of the explosion. If the refinery is out for any length of time, it would obviously continue the tight market.

"We haven't had a cold spell this early or this deep for 30 or 40 years," he added.

But energy experts note that a change in the weather, particularly a

Continued on Page D4

Fire's Effect On Costs of Heating Oil

Continued From First Business Page

warming that has been forecast for the Northeastern United States, would reduce demand and act to hold down prices. If the Baton Rouge refinery is out of commission for a week or less, the impact on heating oil prices should be only temporary, they say.

The Baton Rouge refinery has a capacity to process 450,000 barrels — or 20 million gallons — of crude oil each day. The plant, the largest after an Exxon refinery in Baytown, Tex., accounts for slightly more than 3 percent of the United States' total oil refining capacity.

'Full Conversion' Refinery

The Baton Rouge facility, which has historically been a training arena for Exxon's top management, is known as a full conversion refinery, capable of producing not only the heating oil and lubricating oil that were destroyed on Sunday, but gasoline, which can account for half of the refinery's output at certain times of year. It also produces jet and diesel fuels.

Two heating oil storage tanks were damaged in Sunday's fire. One remained intact, despite a charring of its shell, but the other suffered extensive damage, its roof blowing off and its walls folding in, collapsing the tank to half its height and rendering it useless, said Dave Gardner, an Exxon spokesman at the refinery.

Mr. Gardner identified the man killed in the blast as Harold Guillory, a 31-year-old employee of Vernon McKenny Enterprise, an Exxon contractor. Three Exxon employees and four contract employees who were injured in the explosion and its aftermath were treated at local hospitals and released on Sunday.

Dependent on Pipe Damage

Mr. Gardner said the refinery was closed, although some units were not completely shut down, to ease their start-up after a damage assessment was completed. The ability to resume refining, he added, rested on the harm suffered by a collection of pipe systems that carry oil throughout the plant.

He said the company did not know how much oil from the damaged tanks could be salvaged. Saving some of that oil could have an effect on the prices and availability of domestic heating oil; the 3.6 million gallons in the tanks represents about 3 percent of the 115 million gallons of America's heating oil reserves, Mr. Randol said.

Wholesale prices for No. 2 heating oil, the kind used in homes and commercial businesses, closed at 81.74 cents a gallon on Friday, a rise of 11.3 cents for the week and of about 30 percent during the last month. Mr. Randol said he had heard of retail prices in some areas as high as $1.30 a gallon.

What Mr. Randol termed the "extremely high" prices for heating oil reflected in part the low supplies that existed at the start of the nationwide cold spell. But other factors also combined to place great strains on domestic heating oil supplies.

Not Enough Barges

One industry analyst noted that the intense demand for heating oil in December meant there were not enough barges to bring oil from refineries to local terminals, limiting supplies and raising prices in some areas of the Northeastern and Middle Atlantic states, which account for 75 percent of all the home heating oil used in the United States.

On top of that, "this has been a year of accidents," said Daniel Yergin, the president of Cambridge Energy Research Associates, a consulting firm in Cambridge, Mass. He noted the damage done by Hurricane Hugo in September to an Amerada Hess refinery at St. Croix, in the Virgin Islands, that is even larger than the Exxon plant in Baton Rouge and is an important source of heating oil for the United States.

"Then there was the Exxon Valdez, and there were several accidents in the North Sea over the past few months that damaged supplies," Mr. Yergin added. "And there's still nervousness about what might happen to Soviet oil supplies this winter, because of strikes and internal problems. If Soviet supplies to Western Europe become short, the market here would certainly feel it."

Mr. Lichtblau said that despite the higher prices, consumers have been able to buy all the oil they needed. "There have been no physical shortages, and it looks as if the industry will be able to get through this winter without any," he added.

Despite the cold and the mechanical and natural disasters, a rosy outlook is possible in part because of the weather in Europe, which exports refined oil to the United States.

While much of Europe experienced a cold spell in November, the last month has been quite warm, enabling European refiners to shift their supplies to the United States.

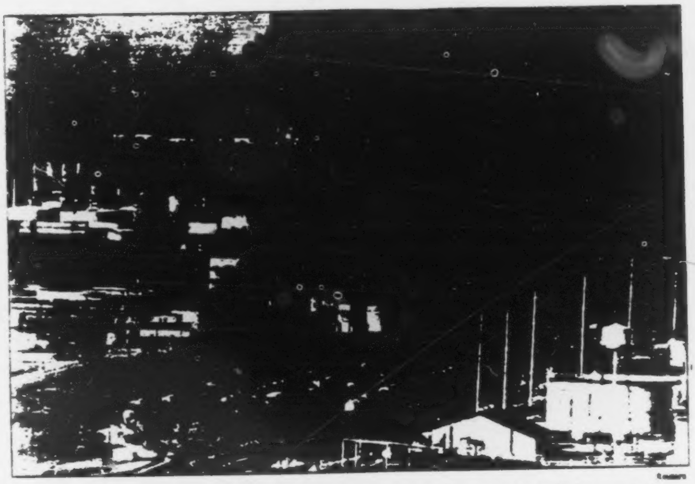
Exxon also says its other refineries, particularly in Baytown and in Linden, N.J., are capable of filling any gap in heating oil for the United States that might be created by damage to the Baton Rouge plant.

Gasoline Inventories High

The Baton Rouge fire is not expected to have any impact on gasoline prices. Because gasoline inventories are currently high, at 227 million gallons, prices are unlikely to rise, Mr. Randol said.

Gasoline is produced as a byproduct of the same process that creates heating oil; increases in heating oil refinement to meet increased demand during the last month have increased inventories.

What is more, demand for gasoline has been weak, down 4 percent during the four weeks from mid-September to mid-October from the same period in 1988, Mr. Randol said. Among the reasons he cited were consumer fears of a weakening economy, artificially high demand last year by middlemen who purchase gasoline from refiners, and slow sales of new cars.



Reuters

Smoke pouring from Exxon refinery in Baton Rouge, La., on Sunday after explosion ignited storage tanks.

Shutdown of Exxon plant here helps push up oil, gas prices

By **BOBBY LAMB**
Advocate business writer

Although Exxon's Christmas Eve explosion in a storage tank area left processing facilities essentially intact, the shutdown of the nation's second largest refinery helped push up heating oil and gasoline prices Tuesday on the New York Mercantile Exchange.

About 170,000 barrels — roughly 7.1 million gallons — of heating oil and other distillates went up in smoke Sunday in an explosion that claimed two lives and rocked the Baton Rouge area.

With the refining operations remaining intact, market analysts viewed the shutdown as only temporary, with no long-term effect on the marketplace.

"It's a temporary negative," said Cliff Haigler, analyst with Howard, Weil, Labouisse Friedrichs Inc.

Exxon's stock slipped a half-point to 50/1 Tuesday, the first day of trading following the explosion, while the January futures price of heating oil jumped 10.7 cents per gallon Tuesday to 92.5 cents on the New York Mercantile Exchange.

Gasoline, which had been declining, shot up by 5.5 cents to 60.9 cents per gallon.

The explosion "had to have something to do with it. I can't quantify it," said Haigler.

But William Randol, an analyst with the First Boston Corp., discounted the effect of the explosion in the heating oil price surge. "It's market psychology is what it is. It's the basic problem. It's not the Exxon explosion. It's that (heating oil) stocks are low and it's cold," he said.

"We're talking a very small percentage of the total," Randol said of the 170,000 barrels lost in the Exxon's explosion.

Exxon now must determine whether its processing facilities sustained any damage from Sunday's shockwave and make repairs before restarting a plant that refines 455,000 barrels, or 18.9 million gallons, of crude oil per day.

"Generally we don't think there was damage to other areas," said Exxon spokesman Walt Eldredge, who compared the plant to an idling car.

No product is being produced at the Exxon refinery, but the system is under pressure to keep equipment warm and prevent any condensation within the system, he said.

On average, 42 percent of the plant's product mix is gasoline; 23 percent is heating oil, diesel fuel and other distillates; 11 percent jet fuel and 10 percent naphtha, or gas-oil, which feeds a nearby Exxon Chemical plant that is idled because of the weather and its sister plant's accident. The remaining 14 percent of the plant's product mix is lubricating oils and other products.

"We can tolerate any reasonable guess at how long we'll be down without any supply interruption," Eldredge said of customer demand for the plant's products. But "as far as anything significant, no, we don't see any problems meeting our commitments."

The explosion was confined to a football field-sized storage area that destroyed two large tanks and several smaller tanks, but the plant has million of barrels of raw crude and refined product in storage in hundreds of other tanks, Eldredge said.

"We have the flexibility within our refining system to augment our supplies," said Jim Davis, an Exxon spokesman in Houston.

Nationally, capacity at Exxon's five domestic refineries — located in Baton Rouge; Baytown, Texas; Bayway, N.J.; Billings, Mont.; and Benicia, Calif. — totals about 1.2 million barrels of crude per day.

The Baton Rouge facility represents about 38 percent of Exxon's domestic capacity.

The impact of the local accident has been compounded by icing conditions that deprived Gulf Coast refineries of natural gas supplies in recent days and resulted in temporary plant shutdowns. Furthermore, an Amoco refinery suffered an explosion Saturday, which also followed a recent accident at the Phillips Petroleum Co. petrochemical plant in Houston.

"In the long term, I think things will balance out. None of the refineries are damaged for the long term," Haigler said.

Meanwhile, Randol said U.S. reserve stocks this year total about 117 million barrels, which is about 9.2 million barrels, or 7.3 percent, less than a year ago.

"You've got a . . . supply/demand problem," Haigler said. "Everybody wants heating oil. If you reduce that capacity at a time when we need it most, that causes the price increase."

Heating oil supplies are tight with the abnormally cold and unusually early winter weather, Haigler said.

As a result, market conditions had already sent prices climbing steadily from around 60 cents per gallon on Nov. 28 toward the current projected January price of 92 cents per gallon in "an extraordinary run-up" that hasn't happened in the past 10 years, Haigler said.

That price is the equivalent of $39.50 per barrel of crude oil, Haigler said. By comparison, West Texas Intermediate — the U.S. benchmark for crude prices — futures prices for February closed at $21.91 Tuesday, up 62 cents per barrel.

With a full winter ahead, Haigler said heating oil prices could remain high. Gasoline prices should contract in a matter of days, once conditions return to some semblance of normality.

Haigler said U.S. refineries are operating at about 92.7 percent capacity, an eight-year high reached this summer

WALL STREET JOURNAL
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Exxon Refinery Blast Kills 1, Injures 6; Mishaps May Tighten Fuel-Oil Supplies

By CALEB SOLOMON
Staff Reporter of THE WALL STREET JOURNAL

Part of an Exxon Corp. refinery in Baton Rouge, La.–the nation's second-largest–exploded Sunday, killing one worker, injuring a half-dozen others and shattering windows for miles around.

The blast was the latest in an 18-month run of refinery and petrochemical-plant explosions and fires that has plagued the oil industry, and could worsen already tight fuel-oil supplies and escalate recent price rises. It came on the heels of an explosion Saturday that killed a worker at a smaller Amoco Corp. refinery in Wyoming.

Cold Weather and Futures

Many traders look to meteorological data to try to gain an edge in futures markets for oil and oil products as forecasters expect this winter to be the coldest since 1983. See story on page C13.

Some oil-industry experts have speculated that reduced plant maintenance combined with maximum operating rates may be contributing to the industry's rash of accidents, though no one has been able to pinpoint a common cause.

An Exxon spokeswoman at Baton Rouge said it was too early to determine what caused the explosion there. She couldn't provide the plant's recent operating rate. But most refineries have been running at or near capacity for some time to meet sustained high demand for gasoline, fuel oil and other products.

The explosion and fire at such a major facility could strain an already tight market for heating oil and other fuels as the Arctic cold continues to grip much of the nation. The frigid weather has sharply increased demand while inventories have been dwindling. In the Northeast, spot shortages of fuel oil cropped up at a few shipping terminals last week.

Any sustained closing – even short term–of the Exxon plant could drive up heating-oil prices, too. At the consumer level, prices have been soaring in the wake of the cold weather and cuts in supplies of natural gas to some industrial users. Plus, hypersensitive commodity traders have been frantically bidding up futures prices, which means the retail run-up was only beginning. Heating-oil contracts traded on the New York Mercantile Exchange have hit three-year highs recently.

The concussion from the Exxon blast, just a few miles from the Louisiana Capitol, could be felt 45 miles away, said Baton Rouge police Lt. Willie Stevens. "This was a major disaster, like an earthquake or something," he said. National Guard troops were called out Sunday afternoon to help stop looting in some areas where store windows were blown out. By Christmas Day, calm had returned to the area. "Everyone is back in their homes. All the streets are open," Lt. Stevens said.

Right now, "much of the refinery is shut down," the Exxon spokeswoman said. The plant has capacity to refine more than 450,000 barrels of crude oil a day. The only larger one in the country is an Exxon plant in Baytown, Texas.

As of yesterday afternoon, refinery officials didn't know when the plant would start up again, the Exxon spokeswoman said. But she said the plant's oil-processing units appeared largely undamaged. Most of the damage and fire seemed limited to two giant storage tanks containing about seven million gallons of heating oil.

The explosion occurred around 1:30 p.m. Sunday and was mostly extinguished by 5 a.m. yesterday, the Exxon spokeswoman said. The blaze, fought by the refinery's fire brigade, the city fire department and surrounding area fire departments, sent plumes of black smoke 500 feet into the air. Exxon even called in experts from Boots & Coots Inc., professional fire fighters from Houston that specialize in oil-industry disasters.

The Exxon spokeswoman said the dead worker, 31-year-old Harold Guillory, was employed by a plant contractor. Three Exxon employees and four contract employees were treated for injuries at nearby hospitals and released Sunday, she said.

The explosion apparently occurred near a group of pipes that move petroleum products from one part of the 2,000-acre plant to another, the spokeswoman said. The refinery, along the Mississippi River, ships most of its products within the Gulf Coast region, she said, adding that she couldn't "speculate" on what will happen to Exxon customers.

On Saturday, an Amoco refinery in Casper, Wyoming, exploded, killing one worker. A butane leak may have been to blame, though Amoco didn't immediately know what ignited the gas. The explosion was in a part of the plant used to produce high-octane gasoline, and the facility will be closed until investigators can determine the cause of the blaze, the Associated Press reported.

These explosions follow a major disaster at a Phillips Petroleum Co. petrochemical plant just outside Houston that killed two dozen workers a few months ago. The Phillips incident led to a series of congressional hearings on plant safety practices. Government and company investigators are still trying to determine the exact cause of that incident.

BUSINESS

MORNING ADVOCATE Baton Rouge, Louisiana Thursday, Dec. 28, 1989

Skyrocketing fuel price spawns call for probe

By JOHN DIAMOND
Associated Press writer

WASHINGTON — Elected officials from northeastern states are turning to Washington for answers to skyrocketing home heating oil prices.

In some New England regions, prices Wednesday were at their highest levels ever and officials voiced suspicion that price and supply manipulation may have as much to do with the problem as the recent cold snap.

The price for a gallon of home heating oil has risen to as high as $1.62 per gallon from about 85 cents per gallon two weeks ago. As a record cold snap gripped the region, prices in New England were routinely jumping 5 cents per gallon per day and in one instance, the jump was 12 cents.

J. Wallace Malley, chief of the public protection division of Vermont's attorney general's office, said, "It's what some people might call a gouge, but we haven't seen any evidence of unlawful practice."

Fuel suppliers blame market forces for the price jumps but public officials, deluged by angry calls from constituents, are calling for an inquiry into whether oil companies are manipulating the price.

Home heating oil, unlike electricity and natural gas, is unregulated and therefore subject to market fluctuations. But Rachel Shimshak of the Massachusetts Energy Office, said regulators are watching closely to guard against price fixing and other illegal forms of industry collusion.

A fuel industry representative rejected the charge of manipulation. "Nothing could be further from the truth," said Bernard Smith of the New England Fuel Institute, which represents 1,300 member companies.

"If you take one word it's 'demand' and the second word is 'weather'," said Smith. While much of the United States is struggling through what may be the coldest December on record, Europe also is going through a cold spell and demanding more home heating oil, Smith said. In addition, cold weather in southern states has caused about a half dozen refineries to shut down or limit production because the temperatures hamper the refining process.

Furthermore, an explosion over the weekend at an Exxon refinery in Baton Rouge, La., caused the heating oil futures market to soar.

Prices this week topped the previous peak of $1.35 per gallon in 1981 at the tail end of the Arab oil embargo, according to Smith. At their lowest level in the past decade, prices for home heating oil were at about 55 cents per gallon during the summer of 1986, according to Smith.

About two-thirds of the homes in New England use truck-delivered heating oil, according to the institute.

The CHAIRMAN. Thank you, Mr. Doniger. I understand you have to be on the House side by 11.00.

Mr. DONIGER. I would appreciate it if the committee would give me leave to do that. There is another hearing over there.

The CHAIRMAN. Let us then have a short round of questions for Mr. Doniger here before he has to go on the House side.

Mr. Doniger, I understand that there are six compounds, arsenic, beryllium, cadmium, chromium, formaldehyde and radionuclides, which, according to EPA, in utility coal-fired and oil-fired boilers, releases of those six would result in two estimated annual cancer cases per year.

First of all, is that right? Bill, do you remember that? The report was entitled "Coal and Oil Combustion Study and Summary Results, 1986."

Mr. ROSENBERG. I would ask Mr. Brenner to answer that.

The CHAIRMAN. Just say yes or no, if you remember it.

Mr. BRENNER. Yes, that is a screening study, and that was the rough estimate in the screening study.

The CHAIRMAN. All right.

I also understand that EPA has estimated that if electric utilities installed bag houses and electrostatic precipitators, that the number of annual cancer deaths could be reduced to .8 cancer deaths.

Mr. BRENNER. That is what that screening study found, right.

The CHAIRMAN. And that is of course after you do the scrubbing.

Mr. DONIGER. Excuse me. That is not correct, sir. That is not scrubbing; that is particulate controls.

The CHAIRMAN. I mean after you use the bag houses, but not taking into consideration the reduction for scrubbers. Is that correct?

Mr. BRENNER. That is for upgraded particulate controls, bag houses and electrostatic precipitators.

The CHAIRMAN. Now the estimated cost of installing such technology was $19 billion in capital costs and $5.4 billion in annual operating and maintenance costs. Is that also correct?

Mr. BRENNER. I believe that is right.

The CHAIRMAN. So if the toxics provision would require that you use the best available technology, which bag houses would seem to be, then would it or would it not require the expenditure of $19 billion in capital costs and $5.4 billion in annual operating and maintenance costs in order to save 1.2 lives a year? Is that fair?

Mr. DONIGER. No, I do not think it is, sir. Because the phrase maximum available control technology under all of these bills is a flexible test, which includes consideration of cost, especially for existing sources, and that is true under all of these bills, including S. 1630.

And it is not a test at which you examine or are driven, at that stage, by the need to—I mean the law would not say you must protect people regardless of the cost. That is not what the law says at any stage. It certainly does not say that at the MACT stage.

And so I would expect that what EPA would do, even if those numbers held up to future analysis, and that was a very primitive study, I am not sure that it would hold up, what I would expect is that EPA would probably find that the controls, especially where ESPs are already in place, are sufficient under the MACT test.

And I am being a realist. I find it unbelievable to expect that under that language in S. 1630 or the Administration bill that the Administration would ever impose bag houses as a retrofit on existing utilities across the country.

And so it is not a realistic scenario under either bill to expect that the $19 billion cost would be incurred. You do not need a specific provision to address that, because it just is not going to happen.

The CHAIRMAN. I simply was not aware that there was that much consideration of cost and economics under the maximum available control technology.

Mr. DONIGER. The definition provides in phraseology which is actually quite similar to existing law, the definition of MACT is greatest degree of emission reduction achievable, considering costs, and the variety of non-air quality effects that are in the normal definitions.

Senator MCCLURE. Mr. Chairman, would you yield on that question, because it is one that is central to one of the major concerns that I have. What you have just said makes it sound like MACT is supposed to be the same as BACT.

Mr. DONIGER. To be honest with you, Senator, in actual practice, I do not think the change from the B to the M is going to make any difference.

Senator MCCLURE. Well, then, why change?

Mr. DONIGER. Because this requirement, in the main, does not—because there is no BACT, MACT, or et cetera, requirement for most of the sources which would be subject to this bill at present.

Senator MCCLURE. But we have some experience with the terms best available control technology for new source performance standards. That is what has been imposed. Now the Administration and the committee have said we are going to use a different term, MACT.

I would assume the courts and the Administration, looking at a change in the law, are going to say some change was intended. If no change is intended, then why change the terminology?

Mr. DONIGER. Well, I can tell you that what we expect to occur under the implementation of the law will be driven not by the name, but by the words of the definition.

Senator MCCLURE. Well, I understand that. But the courts, in trying to make a definition, are going to say Congress intended to do something. We have BACT under new source performance standards today. Congress elected to use a different terminology which presumably is different from that which is already on the books with respect to new source performance standards.

If that is not the intention of the Administration or those supporting the bill, then I would think the best thing we could do to make that clear is to use the existing terminology.

Mr. BRENNER. Senator McClure, I can help to clarify that.

The reason for using a different terminology is that the terms, BACT, for example, apply to individual decisions on sources. And in the case of MACT, we are trying to set a standard for a source category. And in order to make the distinction between case-by-case determinations and source category determinations we felt it was advisable to come up with a different terminology for it.

Senator McClure. You know you have just used more words to further confuse me. You said anything.

The Chairman. Why do we not limit this to Mr. Doniger for the time being, and we can come back.

Mr. Doniger, what you say is this economic flexibility that applies to retrofits, that does not apply to new sources because if anybody has a bag house you have to have one with a new source, do you not, regardless of economic feasibility?

Mr. Doniger. I think that EPA has tended in previous decisions to equate ESPs and bag houses, and I am not sure EPA is on record in saying that bag houses are qualitatively better than ESPs or ESPs are qualitatively better than bag houses.

In previous decisions, I think, including the NSPS in 1979, the agency said what we think is best is achievable by either of these two technologies.

The Chairman. Well, bag house is just part of it. It is either ESP or bag house, it would be pretty expensive.

Mr. Doniger. Well, it is already a requirement for any new utility unit that a bag house or an ESP be installed. That is part of the current new source performance standard. So there would be no incremental technological requirement for new utility boilers on account of MACT, as opposed to existing NSPS.

The Chairman. Let me ask you one other question that has not been raised on HCFCs. Are you familiar with that?

Mr. Doniger. Are you talking now about the ozone section?

The Chairman. Yes.

Mr. Doniger. Yes.

The Chairman. People down in my state tell me that HCFCs are the solution, not the problem. That, in order to have refrigerants you need HCFCs until you discover some new chemical not yet discovered. And they say that it is okay to prohibit CFCs, but HCFCs for the interim need to be allowed.

Mr. Doniger. Well, that is exactly our position, too. And it is exactly the position in the proposal, which Senator Chafee and the environment committee are circulating now.

Let me explain it in this way. Think of these as generations of chemicals. The first generation basically is the CFCs. The second generation basically is the HCFCs. And the first generation is a very powerful ozone-depleting family. The second generation is less ozone depleting, but still has ozone-depleting power.

The third generation, which in some areas, like solvents for example, where you have got other kinds of chemicals, already exist. In refrigerants it is a little further down the road.

But we think that what we need to have is a policy which does not encourage a permanent resting with the second generation. the case of the Chafee proposal, on the order of 25 years from now, there should be a third generation of solutions.

The Chairman. Well, I think my people were concerned about methylchloroform, which is a feedstock for the HCFCs, also used as a solvent. But they tell me that to mandate, in its use of the solvent, a closed system that you can insure no release to the atmosphere, and that you have got to have it to make the HCFCs.

Mr. Doniger. Two things about that.

First, as a feedstock for another chemical, none of these chemicals are regulated in the sense that you can make any chemical, even if it is an ozone depleter, provided what you are using it for is to turn it into another chemical. Feedstocks are exempt.

On the point about the use of a chemical as a solvent. No one has yet demonstrated that they can use a solvent without losing it to the air.

If in fact one were successful in having completely closed systems, then you could make one big batch of methylchloroform and never have to make any more. That is not what the industry is prepared to accept. They are not prepared to say, well, we should be allowed to make a certain batch, and then we will keep recycling in a closed system and using it.

They are asking for permission to continue making 724 million pounds of this stuff every year, and losing that amount to the atmosphere. And if you do that, you cannot solve the ozone depletion problem.

Think of the ozone layer as a great big bathtub in the sky, where there are taps running at a very full bore right now, with chlorinated compounds, and a drain which is almost entirely plugged up.

If we can turn off the taps so that none of the chlorinated compounds are being added to the atmospheric bathtub, then it will stop rising, and instead you will see it start to empty out.

But even under the best scenario, including the phase out of methylchloroform and the limitation on the HCFCs some 25 years from now, and the total elimination of the CFCs, even under that best scenario it will not be until my great, great grandchildren are born in 2075—we are planning ahead, you see—that the ozone hole over Antarctica would go away.

The Chairman. Mr. Doniger, thank you very much for that testimony. I have not seen the Chafee proposal. And this is not the way the problem has been described to me, and you make a very good case. I will go back and talk to these people in Louisiana, on whose jobs this depends, and see if they have got an answer to that.

Does anyone else have questions for Mr. Doniger?

Senator McClure. I just wanted to explore a little further, because I do not know, from what I understand of this, what is intended by the term maximum available control technology that distinguishes that from the best available control technology, a term with which we have some experience.

In your mind, is MACT a higher, stricter standard than BACT, or is it a lesser standard?

Mr. Doniger. Well, I would think that in many specific comparisons it will turn out to be the same. And there will be some instances not relating to boilers where it might turn out to be somewhat more stringent, but mainly because it is a fresh evaluation of the technology now being compared to a BACT, which was determined 10 or 15 years ago.

Senator McClure. But BACT is not applied today on the basis of what was good 10 years ago, if indeed we can do better today?

Mr. Doniger. That is the distinction I think Mr. Brenner was trying to draw between standards for a whole industry, a whole category versus case-by-case determinations for every specific source. The case-by-case BACT determinations, every time a new powerplant comes up there is a new BACT determination. That stays current.

Senator McClure. If the BACT stays current with the current state of the art——

Mr. Doniger. And a fresh determination is made every time a new powerplant comes on.

Senator McClure. Then are you suggesting that MACT fixes it at this time, and as technology gets better it is not adjusted?

Mr. Doniger. What happens is the adjustment comes every five years under the bill, when the standard for that category——

Senator McClure. Well, that means MACT is a less stringent standard than BACT?

Mr. Doniger. It may turn out that if technology is improving that one will move up continuously, plant by plant, and the other will move up in five year increments as the standard is reviewed and updated.

Senator McClure. All right. Then that means that the MACT, over a period of five years, becomes less strict than BACT, until you have your adjustment at the end of that period, when it then catches up with BACT?

Mr. Doniger. I think that is a reasonable way to look at it, yes.

Senator Ford. Why are we using both, then?

Mr. Doniger. Because one program is set up to regulate a category, to set a standard that applies to any specific company that comes along of a specific category or type.

Senator Ford. Mr. Doniger, there is a reason for you being for that.

Mr. Doniger. Well, yes.

Senator Ford. Let me ask you one question, Mr. Doniger. At the very first, when you started talking about risk you cited Texas and the residents near that plant had a one in ten—how large is the plant?

Mr. Doniger. How large is the plant?

Senator Ford. Yes, sir. I am not going to ask you to name it.

Mr. Doniger. Well, I can name it.

Senator Ford. That is okay. I do not care about the name, I just want to know how large is it?

Mr. Doniger. My understanding is it is a very large plant.

Senator Ford. You have not seen it?

Mr. Doniger. I have not been there myself.

Senator Ford. All right. What is a very large plant, 10,000 employees, 2,000 employees, does it cover 10 acres, 20 acres?

Mr. Doniger. I cannot answer that, I do not know. It is a very large petrochemical plant.

Senator Ford. Now, what, under this bill, would that plant have to do?

Mr. Doniger. That plant would in the first instance——

Senator Ford. What is the first instance? What is the deadline for that?

Mr. Doniger. There are two steps under the bill, one is the maximum available control technology standard. That plant emits a pollutant which is covered under the Senate bill in the first group, that has to have these standards.

Senator FORD. But it is not covered under the President's bill or the Administration's bill?

Mr. DONIGER. It is covered under the Administration's bill, but the schedule for its coverage is not as fixed. In the Senate bill that plant has to be covered two years from the day you enact this bill. In the Administration's bill, it could be anywhere from two years to seven years out, I think.

But the principal is that at that point a standard would be set for facilities that emit butadeine, the pollutant in question, that reduce that to the maximum available control technology standard in the sense that we were discussing in the last few minutes.

Senator FORD. That would be the MACT at the time two years from the signing of the bill, and that would not be changed for five years?

Mr. DONIGER. That is right, but for that source, the next step that affects that source is the examination of how much cancer risk is left over, is still occurring after the installation of that so-called maximum available control technology, and the concern we have is that if sources do only what is considered maximum available at a frozen moment in time, that you will still have so much emissions left over from some of them that the health risk will remain very high.

So the purpose of the second step is to have a look at how much health risk remains, and if the cancer risk to the people most exposed is above one chance in 10,000 of their getting cancer, which is a very high risk by public health standards, then a second round of control would be required of that company and of the companies of that type, and the deadline for that would be ten years from enactment with a five-year extension available if they still had trouble, so 15 years from enactment.

Senator FORD. All right. Now, just give me a ballpark figure. Under the bill—the Senate bill, and we have to be careful about this—and the so-called Chafee amendment that gets into refrigerators and all of that, too, you know, and that creates some problems when they are all trying to find a way to get them out. They have cleaned up some of the refrigerators. But anyhow, we will get into that later. What would the cost be in the first phase for the plant, that one plant?

Mr. DONIGER. I do not know.

Senator FORD. Well, what would be the cost for the whole country, then?

Mr. DONIGER. Well, we have a number of estimates from EPA.

Senator FORD. What is your best estimate?

Mr. DONIGER. I think that today's estimates—and I do not have an estimate on my own, but looking at the EPA estimates, what I believe is that the farther out in time you are looking, the less reliable the estimate.

Senator FORD. I asked you, what would the cost be? You do not have a cost, you just want to get it done regardless of the cost, is that it?

Mr. DONIGER. I want to get it done, things that are considered by EPA to be maximum available technology, considering costs.

Senator FORD. How much? Does anybody know? You do not know how much it costs? You do not have any idea?

Mr. **Doniger**. It is going to be different from plant to plant.

Senator **Ford**. What is the national cost, then?

Mr. **Doniger**. The EPA is estimating that——

Senator **Ford**. What is your estimate?

Mr. **Doniger**. Sir, the National Clean Air Coalition does not have a set of specific cost estimates, if that is your question.

Senator **Ford**. The thing is, you come here and tell us to do these things, and then you lean on EPA for a cost figure and then you fuss at them because the cost figure is too low and it does not go far enough and that sort of thing. I would like for you to come here and tell me, we want this done and this is what we estimate it will cost.

Mr. **Doniger**. We want this done because of the health risks and we are at the first step. The MACT test, there is essentially no significant difference of opinion between the Administration and the Senate Environment Committee bill. They are almost the same provision. What we are differing on is whether there should be a follow-on requirement with lead time to protect people's health when the risk remains very high.

Senator **Ford**. Well, Mr. Chairman, I am going to quit. We are getting the life and health out there involved in what started out to be an acid rain bill, and we have had the tack-ons at the end of it that were not even being considered, which was the Chafee bill. That was never really, I think, in this.

So now we have gotten a larger piece of legislation here that goes far beyond, that may have enough weight to carry it down, and I do not want to see that. There is a lot of scurrying around trying to figure out some way that the consumer can pay for it.

Thank you, sir.

The **Chairman**. I think Senator Nickles was next.

Senator **Nickles**. Mr. Chairman, I would just like to hear the other witnesses, if possible.

The **Chairman**. Senator Hatfield, did you have any questions of Mr. Doniger?

Senator **Hatfield**. I had one brief question, since none of us, my staff and I, have seen the Chafee bill, dealing with the ozone producing chemicals. How long is the bridge for the HCFCs?

Mr. **Doniger**. Under a proposal which he has circulated to industry and environment and to a number of members of the Senate, and so there is no secrecy involved here, there is a proposal to allow the HCFCs to remain in use—in any use—until the year 2015. At that point, they cannot be installed in the new product but they can still be manufactured to service existing products.

In other words, if you have a refrigerator, or you are a commercial enterprise with a refrigeration system that depends on that chemical, that system could continue to get chemical until the year 2030.

Now, although you could not put in a new system like that after the year 2015, that is 25 years from now to come up with a third generation and 15 years after that to service and use a unit that was put in even at the last minute with what would then be the old technology.

I do not think there is a business in this country that thinks more than 15 years ahead and so it is hard for me to understand why periods of time like that are not viewed by industry as adequate, and in fact I think the industry is coming around to see that that is a very generous time frame to use for the bridge.

Senator HATFIELD. Mr. Doniger, is that time frame on the basis that that should give the companies long enough to recapture their capital cost for producing these transition chemicals?

Mr. DONIGER. I think it is actually more generous than is necessary to accomplish that. A representative of Du Pont was quoted in the "New York Times" a week or two ago as saying that they anticipate 20-year life cycles which would take them out to 2010 or so, maybe a few years beyond that.

I think that Du Pont—I would be surprised if Du Pont makes investments that they really need 20 years to recoup. There are probably a lot of other investments they could make rather than a 20-year investment, and so I think the time is shorter than he says.

Senator HATFIELD. In effect then, from your estimate, the 20 years would be sufficient and then you would add another five years of grace so that the 25-year date that you are establishing is sufficient, or more than sufficient?

Mr. DONIGER. Considering, as well, that if they built a plant it would continue to produce for the service of the equipment made for that extra 15 years, I think it is more than generous.

Senator HATFIELD. Thank you.

Mr. DONIGER. Thank you.

The CHAIRMAN. Senator Bradley?

Senator BRADLEY. Thank you, Mr. Chairman. I would like to, if I could, explore a little bit with the panel——

The CHAIRMAN. Mr. Doniger had to leave at 11 and we had not finished the whole panel, and so these are just questions for Mr. Doniger.

Senator BRADLEY. I am sorry. Mr. Doniger, could you share with us your view of the idea of relative risk? I mean, are all of the efforts—all of the efforts here on air toxics are going to have a cumulative health effect. It is going to be positive, that is the purpose.

But there are other things that also have health effects, obviously. Say, cigarettes, say radon gas, say a variety of other things that—or say radon and then cigarettes—that are not addressed in the bill, and so what are your thoughts on the whole area of relative risk?

Mr. DONIGER. My thought is that each of those areas you have mentioned is extremely important. I am not sure that cigarette smoking is traditionally considered amenable to Federal pollution control statutes, but as for radon, I think that the Federal Government, the state governments, the Nation needs to be doing a lot on radon protection, because that risk is very high.

But I would ask you also to consider that traditionally in the field of public health regulation we have not been comfortable with the idea that people should be left exposed involuntarily to chemicals they cannot see or hear or do anything about which create risks higher than one chance in one million.

This is a standard which EPA, even in the Reagan Administration, articulated as an approach for the residue of pesticides on food. I do not understand why we should be letting the American people be subject to greater danger when the chemical comes on the wind than when it comes in the food.

Senator **Bradley**. Do you have any specific thoughts about radon gas?

Mr. **Doniger**. No, but I would be happy to supply you some in the future. I did not come prepared to talk about radon.

Senator **Bradley**. Thank you.

The **Chairman**. Senator Conrad, questions for Mr. Doniger?

Senator **Conrad**. Just very briefly, Mr. Chairman, in reading the bill, as we have described earlier the so-called bright line test, the one in a million, the one in 10,000, what concerns me is there is a certain arbitrariness to that kind of standard.

If you then go to the other wording in the bill that says cost is no consideration, it strikes me that you have set up a structure that is not rational. That is, it is okay to have a risk of one in 900,000 but not one in a million even if the cost is dramatically changed, the economic impact is dramatically changed by that kind of standard.

What would your response be to those kinds of concerns? Is there not some other way to achieve the result we all seek to achieve without handcuffing ourselves with a very arbitrary standard that may lead to a set of economic impacts that none of us can foresee at this point?

Mr. **Doniger**. First of all, let me give about a three-part answer. The first is that the bill is not inflexible on the subject of one in a million, as you may have read it. The one in a million standard itself must be set without respect to cost, but the question of whether a source has to meet that is not inflexible as to cost.

When the deadline is approaching for one in a million, companies entitled to an extension of five years and on a repeated basis it can go on indefinitely if it is using all available technology, and the term "available" is discussed in the report as not being a closure standard.

So we would expect that those companies which can meet the one in a million standard with expenses that do not imperil their existence will do that, and those which are having true difficulty with that standard will find themselves asking for and getting the extensions.

We think it is very important, though, that there be a definition of what protects public health and not a cost-benefit definition that is always being watered down by cost considerations.

We do not have, for example, in our civil rights laws a proposition that you protect people's right to fair housing if it is cost beneficial to do so. We do not let children work under the age of 12, or under the age of 16, where it is cost beneficial to do that. There are certain standards which are bright line standards and I think it is perfectly appropriate to apply that in the public health sector as well.

Last, I would say that if you do not have a one in 10,000 bright line, as this bill provides, or any bright line, you get into the following problem, and this is a problem which is the central problem of the EPA administration of the toxic section in the 1980s: it is that when the number of people who are exposed is relatively focused and there is a small number of people that are trapped in an island of high risk because they are the people who live next to the plant and they cannot afford to move—and you do not even know exactly who you are, because you cannot smell or see this gas, you just know that depending upon which way the wind is blowing that there are people who are heavily exposed in that high risk—those people should not be abandoned to live in their high risk situations where the cost-benefit analysis does not work out.

The smaller the number of people, the more focused the high risk is, the more likely EPA is to conclude well, yeah, they are at one in ten risk, or they are at one in 1,000 risk, but there is only five, or ten, or 2,000, or 500 of them and you run out the arithmetic on how many of them are going to die each year and how much a life is worth, and too bad, we just leave them there.

We do not accept that proposition in any other area of social legislation. You do not say, people can have tremendous inequality forced upon them because it is only 100 or 200 people.

There are rights that go to us because we are individuals, we are members of the American society, and this public health protection right, at least some minimal level of protection, should go to everyone, irrespective of the number of people involved. That is why it is so important to have this bright line.

Senator CONRAD. I do not for a minute dispute the rights of individuals to be protected. I think all of us would share that goal. I think the question is—and you have done a very good job of answering some of my concerns about the bright line test—let us say I remain concerned about what the scientific basis is for one in 10,000, or one in a million.

I guess what we are saying, or what you would be saying, is that you have to pick some bright line standard and that that is used elsewhere in the law and therefore that is the justification for using it here. Would that be the crux of the argument with respect to one in 10,000, or one in a million?

Mr. DONIGER. Yes, it is, although I think that that one in 10,000, from the National Clean Air Coalition's point of view that is a big compromise, because the traditional norm in this field has been that risks above one in a million are ones that the EPA is—at least when it is putting its health hat on—has said it is not comfortable leaving people at.

When it puts its green eyeshade back on, it will leave people at one in 100 if the cost benefit does not work out. But from a public health professional's point of view, a one in a million, or greater cancer risk has traditionally been of concern.

We support this bill because it makes a major stride forward, but we do not think that even a one in 10,000 cancer risk should be left permanently and lightly disregarded.

The CHAIRMAN. Mr. Doniger, thank you very much for your excellent testimony. We appreciate your staying here.

Mr. DONIGER. I thank you and the committee and the other witnesses for your indulgence of this schedule. Thank you.

The CHAIRMAN. By the way, we understand there is a new draft of the CFCs. I think it is Title VII. We will want your input on that along with that of the industry as we get it because this bill will be moving fairly fast, and somebody may want to legislate with respect to that.

Thank you very much, Mr. Doniger.

Next we want to welcome James S. Morrison, who is Executive Vice President and Director of ARCO in Los Angeles.

STATEMENT OF JAMES S. MORRISON, EXECUTIVE VICE PRESIDENT, ATLANTIC RICHFIELD CO. (ARCO)

Mr. MORRISON. Thank you, Mr. Chairman and members of the committee. My name is James S. Morrison, and I am Executive Vice President and a member of the board of directors of the Atlantic Richfield Company. ARCO is an integrated petroleum company engaged in all facets of the oil business from exploration to sales of refined products and petrochemicals. We appreciate this opportunity to express our views on impacts of the nonattainment and air toxic titles of S. 1630 and thank the committee for this invitation.

I am going to very briefly summarize the highlights of our written testimony, which is almost as thick as the bill itself. I will be emphasizing modifications to the bill we believe are appropriate. I will not recite all of the supporting reasons, but they are in the written statement filed with the committee.

I first want to say that we strongly support the goal of improving our Nation's air quality and, for that matter, air and other environmental improvements all over the world. Our most recent demonstration of our commitment to clean air is the actual introduction of a cleaner burning reformulated gasoline which we call EC-1 which substantially reduces emissions from older vehicles in Southern California.

We have also done some limited testing of this EC-1 in newer model cars, and we are very encouraged by the preliminary results which indicate that we get significant improvements in the air emissions from the newer cars.

We believe legislation is required to achieve cleaner air, since only through legislation can national standards be set which provide the certainty needed by private companies to make the investments required for improvements.

We also believe—and this is fundamentally important—that achieving clean air and providing energy to the Nation are not incompatible at all. Done right, we can achieve both goals. We must achieve both goals. This is the essence of our comments today, how to make these two goals achievable.

We believe the standards must obviously represent progress towards clean air. Some characterize this as requiring a tough bill. We believe, however, toughness needs to be accompanied by flexibility to enable operations to be adapted to cleaner air needs in the most reasonable manner under the circumstances at hand.

The tighter the restrictions, the less likelihood of adaptations and the greater the chance of unintended results. We feel very strongly that S. 1630 in its present form would create some unnecessary restrictions. Those restrictions can only result in curtailment of domestic petroleum activities. It is one thing to raise costs which can be justified as in the overall interest of America because cleaner air is the reward. It is an entirely different matter to set targets and methods likely to curtail American productive capacity as the means to clean air when the benefits have not been demonstrated nor justified. In any event, we believe curtailment is not necessary to achieve cleaner air.

Innovation and technology are the keys to success when an existing system has to be modified to achieve new environmental goals. The way to do this is for legislators to set the goals and the standards and so far as possible let the means be worked out by the industrial competitors to meet those standards. This theme is critically fundamental to our philosophy in this whole area, and we will be referring to it again and again.

So I would just like to say it one more time. We recognize legislation is needed, legislation to set goals and standards and, wherever possible, not get into telling how to accomplish those goals and standards. Let that be worked out by the American industrial machinery.

Now I am going to review some of the specific concerns we have very, very briefly. A lot of it has been discussed in previous testimony, and so I will make it even briefer than it is written here.

Under the air toxic provisions, sources should not automatically be drawn under stricter controls until shown to be a health risk. For instance, overly strict emission controls could fall in remote oil wells and gathering tanks, and this should not be required as a standard practice. S. 1630 has the potential to shut in 29,000 oil wells which represent a producing rate of about 143,000 barrels per day and would result in losing domestic reserves on the order of some 500 million barrels of oil.

Next, while lowering the risk is by definition desirable, we should not aim so close to a zero risk as to effectively order the shutdown of facilities. The residual risk definition in S. 1630 will have that result. For example, according to an EPA study for benzine NESHAPS, if one 1 million unit risk were to be imposed, 131 of the refineries and chemical plants in that study would have had to cease operation.

We unfortunately are not a one-issue society. We face and will always face a matrix of problems and excesses in one area to work to the detriment of others. Balance is what is needed, and if the definition results in this kind of impact we do not think it is balanced. We should not be dealing with hypothetical people and hypothetical situations. We should be dealing with actual people in actual situations.

Also, a portion of the bill calls for the transfer of the offshore activity from the Department of Interior to the EPA. We believe the Department of Interior are the offshore expert, and, among other things, they are already required to enforce the Clean Air Act. Consequently, we see absolutely no purpose in transferring this authority for air matters relating to offshore activities away from the Department of Interior.

Next, nonattainment provisions will severely hamper, if not destroy, our ability to develop and manufacture new products like the EC–1 gasoline that are environmentally preferable to the products now being produced. The reason is that elimination of netting and bubbling and tighter offset requirements may make permitting impossible, in which case we will be in the ludicrous situation of not being able to build new facilities to improve the environment. This result cannot be anyone's intention.

Next, we question whether the societal costs and effort associated with controlling sources below the 100 ton per year level down to 25 or even 10 tons is necessary in all cases. An analytical assessment showing the air quality benefits versus the cost for such a requirement should be conducted before the law is changed. The resultant impacts are just too great to order this action by definition.

One last point. The more stringent controls for nonattainment areas should not be extended to the entire MSA/CMSA area or buffer zone unless it can be demonstrated that sources in those areas contribute to the nonattainment problem in the core area. The increase in size that will be automatically ordered up will be very significant. As an example, Tulsa's existing 570 mile area would rise to some 5,000 square miles, a tenfold increase.

That concludes my remarks, Mr. Chairman. I will be pleased to try to answer your questions. If I am unable to do so, I have an associate with me who is very well versed in these technical matters and, if I may, I would refer technical questions to him.

[The prepared statement of Mr. Morrison follows:]

TESTIMONY OF

ATLANTIC RICHFIELD COMPANY (ARCO)

TO THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

ON

IMPACTS OF THE NONATTAINMENT AND AIR TOXICS SECTIONS OF THE PROPOSED CLEAN AIR ACT AMENDMENTS, S. 1630 ON THE PETROLEUM INDUSTRY

PRESENTED BY

JAMES S. MORRISON

JANUARY 25, 1990

WASHINGTON, D.C.

TESTIMONY FOR SENATE ENERGY COMMITTEE HEARING
JANUARY 25, 1990

by James S. Morrison, Executive Vice-President
Atlantic Richfield Company

IMPACTS ON THE PETROLEUM INDUSTRY OF NONATTAINMENT AND AIR TOXICS SECTIONS OF CLEAN AIR ACT LEGISLATION

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Testimony of J.S. Morrison
Atlantic Richfield Company (ARCO)

Senate Energy and Natural Resources Committee
January 25, 1990

INTRODUCTION

My name is James S. Morrison. I am Executive Vice-President of Atlantic Richfield Company (ARCO). We are primarily an integrated petroleum company. We are pleased to share our views of the impact of the nonattainment and air toxics sections, Titles I and III of S. 1630, on the petroleum industry.

At the outset of this testimony, I want to reaffirm the position that ARCO strongly supports the nation's goals to improve air quality. An example of our public commitment to those goals is our introduction of a reformulated gasoline - called EC-1 - that substantially reduces emissions from older vehicles.

While new clean air legislation should be tough, it also should be flexible. It should allow industry to accomplish our nation's clean air goals, update our technology and processes, and still be responsive to changes in consumer demands. Further, we must compete in world markets - an important part of the national agenda, as well.

OVERVIEW

If S. 1630 were enacted as proposed, the restrictive rules and regulations called for in the nonattainment, air toxics and permitting titles would decrease the ability of the petroleum industry to explore for and produce domestic sources of oil and gas. The bills restrictions would severely hamper, if not destroy, our ability to develop and manufacture new products that are environmentally preferable to the products we now produce. Further, the bill would freeze the status quo of our technology; stifle the ability of our industry to innovate; eliminate the necessary flexibility to operate in the most economic way possible; and ultimately drive petroleum production and manufacturing of products predominantly to foreign countries. The potential consequences are quite clear.

One of our chief concerns is that provisions of S. 1630 create a contradiction, by mandating product changes while eliminating the flexibility needed to obtain permits to make those changes - either voluntarily or involuntarily. The restrictions even apply to changes that would improve air quality - such as the manufacture of reformulated gasoline.

As requested by the Committee, we have evaluated below the impacts of certain nonattainment and air toxics provisions (Titles I and III). We have also included suggestions for revisions which will make it possible for industry to be responsive to the goals of the Clean Air Act in the most expeditious and cost-effective way possible.

COMPARISON OF APPROACHES - SENATE BILL vs ADMINISTRATION

Before we discuss specifics, we would like to comment on our perception of the general approach to air quality management of the Senate and Administration bills. The requirements of S. 1630 are stringent and tend, for the most part, to be inflexible. The Administration bill also has stringent requirements, but, on the other hand, tends to allow for some operational flexibility. The petroleum industry is not a static business. Products and processes have to change to meet the demands of consumers, as well as the demands for air quality improvement. If operational flexibility is denied, our ability to respond to new demands is either limited or destroyed. Because, updating technology, as a rule, means better environmental performance of our facilities; we generally support the Administration's approach to the nonattainment and air toxics provisions.

COMMENTS ON TITLES

The following is a detailed discussion of the more important provisions of the nonattainment and air toxics titles. We will generally follow the format of (1) describing the provision, (2) setting forth our understanding of how that provision will operate, (3) presenting our perception of how the provision will impact the petroleum industry, and (4) making recommendations to improve the legislative language.

COMMENTS ON TITLES

NONATTAINMENT

O ELIMINATION OF NETTING/BUBBLING

ISSUE

§106 (starting on line 13, page 184) eliminates the ability to net out and/or bubble emissions within a facility by requiring each new and/or modified existing source to obtain a permit subject to new source performance standards and to more stringent offset requirements.

This is a substantial change from the current law which permits changes or modifications within a plant to occur in an expeditious manner, providing that such a change can be accomplished without increasing overall emissions up to an amount triggering new source review requirements. In practice, the volume of emissions permitted under a "bubble" keeps shrinking as districts promulgate new rules for various sources within the bubble.

IMPACTS

Elimination of the ability to net and bubble within a facility establishes construction/modification road blocks that will work against improved productivity, upgraded technology and better performing plants, thus undermining industry's ability to be responsive to changes in consumer demands, improved technology, and international competitiveness. We cite several examples of how netting and bubbling have worked, in practice.

Case 1. ARCO's Los Angeles Refinery, located in California's South Coast Air Quality Management District, is subject to the District's Rule 1109 which deals specifically with the control of NOX for refinery heaters and boilers. Rule 1109 is written as a bubble rule for refinery-wide emissions of NOX from heaters and boilers.

In the period 1985-1988, ARCO was able to build a cogeneration facility based, in part, on the bubble concept. The first phase of compliance with Rule 1109 was achieved by substituting a highly-controlled set of gas turbine generator/waste heat boilers for 40 year old conventional steam boilers. This cogeneration project had three chief environmental benefits: (1) installation of state-of-the-art technology with attendant energy performance and emissions control efficiencies, (2) substantial reductions in refinery-wide NOX emissions - more than was required to comply with the first phase of Rule 1109, and (3) conversion of what would otherwise have been waste heat into electricity which was sold to the local utility.

In the absence of the bubble concept, this project would not have been built. Instead, in order to comply with Rule 1109, we would have been forced to retrofit the old boilers with 1990 stack gas treatment for NOX. Such a solution would not have been as energy efficient as the cogeneration solution; it would have been considerably more expensive to operate; and it would not have resulted in the emissions improvements that we are now experiencing. In this case, the bubble concept fostered an innovative solution to the NOX compliance problem that was, at the same time, more energy efficient and less costly - a triple benefit - not only to the environment, but to the consumer as well.

Moreover, we were able to bring the cogeneration unit on line nearly six months ahead of the regulatory schedule, thus making the environmental benefits available substantially sooner than if the bubble concept had not existed. Elimination of the bubble concept would have forced a worse solution to the problem - in all respects - and would have taken longer to achieve, because of the potentially more cumbersome and time-consuming permitting process.

Case 2. At our other refinery, located at Cherry Point in the state of Washington, there exists an air pollution control rule based on the bubble concept that limits another criteria pollutant, sulfur dioxide (SO2). The rule is written in terms of pounds of SO2 emitted per million BTU of heat input to furnaces and boilers.

In this case, we needed to improve the quality of one of our product lines because of consumer demands. The process for accomplishing this, however, emitted sulfur dioxide. We were able to design and install a process which included a wet scrubber for sulfur removal combined with a waste heat boiler. The waste heat boiler produced steam from heat that would have otherwise been thrown away, and this allowed reduced firing of the refinery's direct-fired steam boilers. The resulting reduced SO2 emissions from the main boilers, coupled with the SO2 emissions from the sulfur removal process, preserved the integrity of the overall SO2 emissions cap from the refinery. There was also substantial environmental benefit because the waste heat recovery allowed resource savings in terms of the fuel that would have been burned in the direct-fired boilers not to mention the fact that the product, as consumed, would produce less SO2 emissions. This solution was made possible in an expeditious way, in part, because of the bubble rule for SO2.

Moreover, since all refining processes must be shut down periodically for inspection and maintenance - meaning that they are not in operation perpetually - the return of the refinery to full operation during these shutdowns, with full use of the main steam boilers, still preserved the integrity of the SO2 emission limits of the refinery. Thus, the bubble rule permitted the necessary operational flexibility for operating sulfur removal equipment and fostered the most reasonable technical solution for compliance while maintaining refinery-wide SO2 emissions levels. Elimination of the bubble rule would have forced a more costly and energy intensive solution with little, if any, additional environmental benefit.

Case 3. An even more dramatic case is ARCO's decision to manufacture a reformulated gasoline at our Los Angeles Refinery. This new gasoline - EC-1 (Emissions Control, first of a series) - was specially designed to improve emissions performance from pre-catalytic model cars. EC-1 type gasolines, if used by all pre-catalytic autos in the Los Angeles Basin, would reduce mobile source emissions by 350 tons per day. [This potential emissions improvement was confirmed by both the local and state air quality management agencies.]

Since the refinery was configured to produce a marketable quantity of this product without significant operational changes, we were able to bring it on line in six months from the inception of the idea. Other refineries, however, including our refinery at Cherry Point, Washington, are not configured to produce such a product without new construction and/or modification.

The elimination of the netting/bubbling rule, combined with the new offset requirements, will make it more difficult, if not impossible, for other refineries to produce a similar product. Moreover, instead of bringing the product to market in six months, it may take as long as two to three years, assuming that sufficient offsets are available to get permits.

Prospectively, we are now investigating the manufacture of EC-X for newer catalytic equipped model cars. We have done limited testing of EC-1 in state-of-the-art 1989 model cars and are very encouraged by the test results. The percentage reduction in exhaust emissions in the new cars is about equal to or greater than the percentage reductions in old cars.

For example, limited testing on five 1989 low-mileage vehicles shows about a 12% reduction in exhaust hydrocarbons (vs about 4% in non-catalytic vehicles), about a 22% reduction in carbon monoxide (vs about 9% in non-catalytic vehicles) while nitrogen oxide emissions are cut about 3% (vs about 5% in non-catalytic vehicles). The reduction in benzene emissions in both the new and the old cars is about 40%. These new cars have very low evaporative emissions. As a result, we found no reduction in evaporative emissions from the new cars, while the old cars showed an evaporative emission reduction of about 21%. We are now in the product formulation testing phase for EC-X.

While our Los Angeles refinery needed only minimal modifications to produce EC-1, the production of EC-X will require more substantial changes in refinery configuration and operation. We are looking at potential capital costs of $2 billion to make these changes in two of our refineries. However, before we decide to invest in manufacturing EC-X, we need two fundamental assurances: (1) that government fiat (whether by legislation or regulation) will not suddenly disqualify reformulated gasoline as a clean automobile fuel, and (2) that we will be able to get permits to construct and modify the required facilities, as well as to operate our plants. Of course, we will bear the economic risk of the marketplace if we decide to manufacture EC-X, as we did with EC-1. As written, the Senate Clean Air proposals do not offer those assurances - the elimination of netting and bubbling being one of the factors that will affect our ability to manufacture the product.

CONCLUSIONS/SOLUTIONS

ARCO's refinery in the Los Angeles Basin is unique in the sense we were able to manufacture marketable quantities of EC-1 without major changes in the facilities. Not all refineries are configured in the same way. Some refineries will need major modifications to produce a reformulated gasoline and will need the flexibility to do so. To promote better environmental performance of fuels we will need to innovate, modernize, and increase efficiency, and we will need the flexibility to do so.

Elimination of netting and bubbling will make it difficult for those who are already tightly controlled to upgrade facilities. Further, operational flexibility will be reduced, costs will increase and technology - the status quo - will be frozen. Industry's ability to innovate and compete will be undermined. Even more importantly, the manufacture of new environmentally superior products, such as reformulated gasoline, will be all but impossible.

The ability to net and bubble within a facility should be retained by changing §106 language in the following way:

Delete lines 13 through 23, page 184.

- **OFFSET REQUIREMENTS**

ISSUE

§107 (starting with line 23, page 206) establishes offset requirements for volatile organic compounds (VOC's) of 1.5 to 1 in serious nonattainment areas, and offset requirements for both VOC's and oxides of nitrogen of 2.0 to 1 in severe and extreme nonattainment areas. This is a substantial change from the current law, as it operates in practice, which calls for offsets of slightly more than 1 to 1.

IMPACTS

The proposed requirement for increased offsets will have several important consequences for industry:

- For new facilities, the logical progression of this stringent offset requirement results in a construction ban. In the early phases of this requirement, exploration and development of new oil and gas sources, as well as new construction in refineries and other petroleum industry segments, will be slowed as potential permittees scramble for emissions offsets. Finally, as offsets become scarce or not available, development of reserves and construction of new facilities in serious, severe and extreme nonattainment areas will cease. The more stringent the offset requirement, the sooner the de facto construction ban will materialize.

- For existing sources that are to be modified, the same type of construction ban would be the eventual result, though in a more insidious way.

  - For instance, if a plant were to modify a permitted facility [and netting and bubbling were eliminated], the modified configuration would now be subject to the more stringent emissions performance standards of "new source review."

- To add a further complication, suppose the modification would produce a product that would result in lower emissions in another area such as the nexus between the manufacture of reformulated gasoline and reduced mobile source emissions. If the reduced mobile source emissions were required by law, then these reduced emissions would be excluded - in any amount - from qualification as offsets for the manufacture of the precursor product. Thus, we would find ourselves in a "Catch-22" situation. The manufacture of reformulated gasoline would be required, but producing that product might not be permitted if offsets were not available to either construct new facilities or modify old ones.

- As with the elimination of netting/bubbling, the requirement for increased offsets will discourage, or even render impossible, both construction and modifications of existing facilities to meet new product demands. Ultimately, these and other requirements of the bill will drive manufacturing operations to foreign countries.

IMPACTS ON THE PETROLEUM INDUSTRY

For a project in the 1985 time frame, we needed emissions offsets and sought to purchase them on the open market. Despite extensive efforts to locate available offsets, our search was unsuccessful. We can only conclude that owners of emission credits recognize the importance of such offsets to their own operations, so are unwilling to part with them.

In this case, and likely in others to follow, we will have to look to our own operations to get offsets. This casts a pall over the entire idea of reducing pollutants by getting offsets from sources outside a facility. A de facto construction ban is already in place for new facilities in California's South Coast Air Quality Management District, and it is likely to be true for other areas as well.

An unintended consequence of the offset requirements is that a major polluter in a nonattainment area may choose to continue to operate, even at an economic loss, awaiting a buyout of offsets at an inflated price due to forced offset acquisition. Such a result would be counterproductive.

CONCLUSIONS/SOLUTIONS

Increasing the stringency of the offset requirements for new sources and modifications provides a strong incentive to maintain the status quo. Ultimately, and even now, such a requirement will tend to drive manufacturing to foreign countries and prohibit exploration and development of new domestic oil and gas sources. Stagnation of the industrial sector will freeze economic growth and undermine our competitiveness in the world market.

ARCO recommends that offset requirements be designed to not only improve air quality, but also allow sufficient flexibility for change and economic growth. This outcome can be achieved by changing the language in §107 as follows:

On line 2, page 207, change, "at least 1.5" to "no more than 1.1."

On line 3, page 207, change, "at least 2" to "no more than 1.2."

On line 6, page 207, change, "at least 2" to "no more than 1.2."

Moreover, to ensure that facilities can be modified to manufacture environmentally beneficial products with net improvements in air quality, language in §106 should be changed as follows:

Insert "(1)" after "(c) Offsets. --" on page 189, line 16.

Insert after line 5, page 190:

> "(2) A new major stationary source or a major stationary source that is modified for the primary purpose of producing fuels or any other product that will result in reductions in emissions from mobile or other sources may comply with any offset requirement in effect under this part by taking credit for prospective emissions reductions in the use of that product, either mobile source emissions or other emissions, in the ratio of 2 to 1 (i.e. two tons of mobile source emissions improvement for 1 ton of plant emissions)."

o **AUTOMATIC EXPANSION OF METROPOLITAN STATISTICAL AREAS/ CONSOLIDATED METROPOLITAN STATISTICAL AREAS (MSAs/CMSAs)**

ISSUE

Section 101 (starting on line 6, page 163) revises, by law, the boundaries of current ozone nonattainment areas to encompass the entire MSA/CMSA in which the nonattainment area is located. This section allows a state 60 days to demonstrate that portions of the MSA/CMSA should not be included in the expanded nonattainment area redesignation. However, such demonstration will be extremely difficult, if not impossible, to make within a 60-day period. The burden is on the state to demonstrate that sources in areas which are now classified as attainment, which are in the MSA/CMSA, do not contribute to violations of the standard in that portion of the MSA/CMSA that is actually in nonattainment, and further that there is a geographical basis for excluding the attainment area from reclassification as nonattainment.

States are unlikely to undertake such a demonstration for at least three reasons. (1) The time allowed (60 days) is simply too short to do a credible job, (2) it is not statistically possible to prove a negative event, and (3) the default of not making the demonstration would give an agency authority over a larger area. In short, there is no incentive to embark on such a demonstration.

The provision to expand the nonattainment areas will more than double the number of counties subject to nonattainment regulations based on an arbitrary geopolitical boundary [that may have no relevance to nonattainment]. Moreover, there is no evidence that the area expansions will guarantee satisfactory air quality.

IMPACTS ON OIL AND GAS EXPLORATION AND PRODUCTION

Significant amounts of additional territory will become subject to nonattainment controls, particularly as counties in the West and Southwest are quite large. Since oil and gas exploration and production operations rarely occur in urban settings, but in the outlying countryside, they will be particularly hard hit by this provision. An oil and gas facility could be many miles from the boundary of a nonattainment area, making no contribution to nonattainment, and still be subject to the expanded control requirements of a nonattainment classification. For instance, the Tulsa County nonattainment area would expand from the existing county to four additional counties, adding 4,400 square miles. It is improbable that all 4,400 square miles are contributing significantly to the city of Tulsa's marginal nonattainment problem.

A further provision states that all areas except those classified "moderate" must include sources in their inventories 25 miles beyond the boundary of the MSA/CMSA. The impact of this plus-25 mile area expansion can be quite significant. For example, by expanding the Houston/Beaumont-Port Arthur nonattainment areas to include the entire MSA/CMSA, the size of the nonattainment area doubles; by expanding another 25 miles beyond the boundary, the nonattainment area would more than quadruple, going from roughly 5,000 square miles to 22,000 square miles. The result would be the addition of many new sources in the inventory program that could be as much as one hundred miles from the original nonattainment area. This increased resource commitment to conduct inventories on an automatic basis would likely contribute little to the solution of the nonattainment problem.

The impact of the automatic nonattainment area expansion to include entire MSA/CMSA's, coupled with buffer and other nonattainment provisions in the bill, will heavily impact oil and gas exploration and production. For instance, if source sizes to be controlled are reduced, retrofit control of nitrogen oxide sources required, permits required on both new and existing sources, as well as offsets for constructing or modifying facilities, costs of oil and gas operations will escalate dramatically. We have not conducted a study to determine cost impacts of MSA/CMSA expansion alone, but using Tulsa as an example, the number of oil and gas sources included would increase 1,500 percent (from 21 facilities to over 300). These sources could potentially be subject to many of the nonattainment requirements of the Clean Air Act Amendments.

CONCLUSIONS/SOLUTIONS

ARCO supports the notion that to the extent adjacent areas contribute significantly to a core county's nonattainment problem, sources in those contributing areas should be subject to control. However, we believe that automatic expansion of the nonattainment classification to an entire MSA/CMSA is not an appropriate or effective way to address this problem. It would be a much better use of resources to first determine which specific segments of adjacent areas make a significant contribution to nonattainment and then expand the nonattainment classification to include just those areas. The state - on a case-by-case basis - should be required to make a finding that a nonattainment classification should be extended to specific areas within an MSA/CMSA. Such a finding can be developed by analysis of local meteorology, dispersion modelling and/or ambient monitoring.

We suggest that the legislative language in §101 be modified in the following way:

Delete lines 9 through 24 on page 163; and lines 1 through 6 on page 164, then substitute the following:

> "(2) In the case of any area which is designated as a nonattainment area for ozone and is classified as severe or extreme pursuant to §107 or this section, the Administrator may, after consultation with the State in which such an area is located, modify the boundaries of the area by rule to include all or part of the metropolitan statistical area or consolidated metropolitan statistical area, as the case may be, if the state determines that such a modification, based on modelling and monitoring, is necessary to attain the ozone air quality standard in the referenced nonattainment area. Such boundary revision shall apply for purposes of any State Implementation Plan revision

required to be submitted by the State.

On line 22, page 213, place a "." after "182(a)(1)" and delete the remaining part of line 22 through line 25, and delete lines 1 and 2, page 214.

Delete lines 16 through 25, page 221, and delete lines 1 through 9, page 222.

O DEFINITION OF SOURCE SIZE

ISSUE

The existing major source definition triggers permitting, permit fees, offset requirements for the construction or modification of such sources. Sections 106 and 107 change the current concept of major stationary source. §106 extends the 100 ton per year threshold to include the sum of all precursors of ozone, whereas in the past, the 100 tons per year threshold applied only to one precursor, volatile organic compounds (VOCs). Under the new definition, a source could emit 25 tons per year of VOCs and 75 tons per year of nitrogen oxides (NOX), or one ton per year of VOCs and 99 tons per year of NOX, and be considered a major source. Such a requirement is inappropriate in the face of the persistent uncertainty regarding the efficacy of controlling NOX in improving ambient ozone levels.

Even more importantly, the threshold for classification as a major source is drastically reduced. For Serious Areas, the VOC threshold is dropped 75 percent to only 25 tons per year, and retrofit technology is required for sources of 25 tons per year of VOCs and 100 tons per year of NOX. In Extreme Areas, a 90 percent reduction is made for the VOC threshold - to 10 tons per year. Also, retrofit technology is required for all sources of either 10 tons per year of VOC or NOX.

IMPACTS ON OIL AND GAS EXPLORATION AND PRODUCTION

Oil and gas operations are not consolidated into one large facility. As a rule, many small sources are scattered through generally rural areas. By lowering the size of source subject to permitting and control, and by expanding the physical size of the ozone nonattainment areas, many more sources will be swept into the regulatory net. Of particular concern is the requirement that existing NOX sources be retrofited with Reasonably Available Control Technology (RACT) - even though reducing NOX may actually exacerbate ozone formation.

CONCLUSION/SOLUTIONS

We suggest that NOX not be included in the statutory definition of major stationary source ozone precursors or in the automatic RACT requirements applicable to ozone sources. States should be given the flexibility to permit and control NOX sources on a case-by-case finding that such controls will result in positive air quality benefits in a particular nonattainment area. The VOC source definition should not be reduced without a demonstration by the state that additional sources in an individual area need to be controlled to achieve attainment of the ozone standard.

We recommend that §106 be modified in the following way:

Change line 20, page 184, to read:

> "more per year of a pollutant or a precursor of a pollut-"

In §107, on line 8, page 213, starting after "AREAS. --" delete through the period (".") on line 14, page 213.

In §107, delete lines 10 through 16 on page 222.

O **MANDATED ANNUAL EMISSIONS REDUCTIONS**

ISSUE

§107 (starting on line 3, page 214) calls for annual emissions inventory reductions of four percent averaged over each consecutive three-year period. All emissions reductions, whether mandated by federal, state, or local agencies, with the exception of fuel volatility regulations (Reid Vapor Pressure reductions), may be credited toward these annual percentage reductions.

Mandated annual emissions inventory reductions for the sake of simple inventory reductions - while an intuitively appealing concept - may not, in actual practice, improve air quality - as defined by achieving the National Ambient Air Quality Standards (NAAQS). The reason is obvious. Sources controlled for the sake of mandated annual emissions inventory reductions may be geographically located in such a way that they may have little or no impact on exceedences of the NAAQS as measured by ambient air quality monitors.

We support the concept of a requirement for progress in the improvement of air quality. But, we submit, mandatory reductions in emissions inventories are not a direct measure of, nor will they automatically result in, improvements in air quality. Certainly, air quality must be improved with reductions in emissions, but conversely, emissions reductions, by themselves, are not a reasonable measure of air quality improvement in areas that exceed the standard. Therefore, instead of simply measuring emissions reductions, we should measure actual improvements in air quality.

However, "design value," the current criteria by which air quality is measured, is a grossly inadequate yardstick by which to measure air quality improvement. A new measure is needed, one that reflects population exposure as a function of the pollutant level above the standard as well as the number of people exposed. The proposed legislation has no provision that would address the development of this critical criteria.

Further, in projecting improvements to be contributed by specific control measures, modelling analysis should be required for each proposed measure. Cost-effective analyses can then be conducted for each potential control measure and the most cost-effective strategies employed first. This approach is more apt to guarantee achieving the goals of Clean Air Act legislation in a more expeditious, certain and cost-effective way than the requirement that emissions inventories (whatever their actual impact on air quality) be reduced by a specified annual percentage decrement.

In the second place, volatile organic compound (VOC) emissions inventory reductions that result from reduced fuel volatility - Reid Vapor Pressure (RVP) - will result in reductions of ozone precursors. It makes little sense, then, to exclude this single source as a credit in the calculation of required annual reductions in emissions inventories. Under the theory embodied in the bill, VOC reductions - from whatever source -contribute to improvements in air quality. Certainly, the petroleum industry and the motoring public will pay for these RVP reductions and they should be given credit in any calculation of required emissions reductions.

IMPACTS

The impacts of the percentage inventory reduction provisions on the petroleum industry are difficult to quantify, because it is virtually impossible to foresee the precise direction that the agencies will take. But we can be certain that percentage reduction requirements will force agencies to go back to those sources that are already controlled, whether or not such a strategy gives the public the most effective air management program for the least cost.

CONCLUSIONS/SOLUTIONS

As a solution, we would direct the attention of the Committee to testimony that was delivered by the Clean Air Working Group (CAWG) to the Senate Subcommittee on Environmental Protection on September 27, 1989, by Dwaine H. Smith. We would be pleased to provide a copy of that testimony to the Committee. In brief, the testimony provides a blueprint for a more effective, certain, reliable and minimum cost-solution to the management of air quality.

Requiring EPA to Develop a Better Measurement of Progress than Emissions Inventory Reductions

The current "design value" method of measuring air quality is grossly inadequate for measuring progress toward attainment. The Environmental Protection Agency should be charged with developing a more reasonable and reliable measure. Moreover, once developed, this measure should be used in developing meaningful progress milestones in air quality improvement requirements. (See language below.)

Exceptions to Mandated 12 Percent Inventory Reductions

Further, the legislative language should allow an exception from the percentage reduction requirement if progress toward attainment is demonstrated according to the required schedule. This can be accomplished with the following legislative language:

At line 18, page 202, add a new section as follows, and resequence the remaining sections:

> "(c)(1) The Administrator shall conduct a study to develop measures of nonattainment and methods of classification that are superior to design value as an indicator of ozone air quality. The study shall be completed within one year of the passage of this act including the opportunity for public hearings and comment. Upon completion of the study, the Administrator shall commence a rulemaking

proceeding pursuant to subparagraph (2).

(2) The Administrator shall, by rule, modify the classification system and the classifications set forth in paragraph (a). Any such modification shall take into account any other factors determined by the Administrator to be appropriate.

(3) The Administrator shall use the resulting measure of air quality (other than design value) in the measurement of progress toward achieving attainment deadlines in subparagraph (new d) [as resequenced] and establish criteria for satisfactory progress which can be substituted for the requirements under "Sections 183(b)(2), 183(3)(B), and 183(d)(3)(A)"."

Credit for Reid Vapor Pressure Reductions

Should the mandated annual emissions inventory reduction provisions prevail, the reductions derived from Reid Vapor Pressure regulations for fuels should be counted in calculating the annual inventory reduction. This can be accomplished by changing §107 as follows:

On lines 12 and 13, page 214, delete the parenthetical phrase, "(other than rules promulgated under section 211(h))."

On lines 17 and 18, page 215, delete the parenthetical phrase, "(other than rules promulgated under section 211(h))."

o TRANSFER OF OCS AIR EMISSIONS JURISDICTION FROM DEPARTMENT OF INTERIOR TO THE ENVIRONMENTAL PROTECTION AGENCY

ISSUE

Section 111 transfers jurisdiction over Outer Continental Shelf (OCS) air emissions from the Department of Interior to EPA, directing EPA to control these sources as if they were located onshore and to delegate authority to state agencies.

IMPACTS ON OIL AND GAS EXPLORATION AND PRODUCTION

The proposed transfer of authority will greatly impact all

OCS areas including, particularly, the Gulf of Mexico. An industry estimate of the impact of a similar provision in an earlier air bill was about $300 million over a five-year period in the Gulf of Mexico. This cost would be imposed without any demonstration that OCS operations were adversely impacting onshore air quality, and the expensive controls would yield little or no benefit. For example, platforms located greater than 100 miles from shore could be regulated as if they were located in the midst of a large population center. One assumption behind this proposal has to be that EPA will more closely supervise and restrict exploration and production operations. It also assumes that current operations are not closely monitored and no proof of this charge exists.

From an administrative standpoint, limited personnel and resources available to the state and local agencies may contribute to delays in permit processing, critical in developing OCS leases. Further, it would be difficult for state and local agencies to maintain a national perspective when considering approval of OCS development projects.

CONCLUSION/SOLUTIONS

ARCO supports maintaining authority for OCS air quality with the Department of Interior (DOI). The DOI is obligated to comply with the Clean Air Act requirements; therefore, there is no need to transfer jurisdiction to EPA. Duplicate authority over operations can only delay decisions and render operation uneconomic at an earlier date. If Congress believes that some statutory change is necessary to address unusual situations, then legislation should address those concerns within the framework of DOI.

We recommend that §111 be deleted by deleting lines 3 through 26, page 275, all of page 276, and lines 1 through 9, page 277.

O **REASONABLY AVAILABLE CONTROL TECHNOLOGY ON NOX SOURCES**

ISSUE

§ 107 (pages 217-218) requires that Reasonably Available Control Technology (RACT), be installed on all volatile organic compound (VOC) sources of 25 tons per year and greater and on all NOX sources of 100 tons per year and greater, in all ozone nonattainment areas except moderate areas. Since RACT entails retrofiting an existing source, it can be one of the most technically difficult and costly provisions of the Clean Air bill. Therefore, inclusion of broad, additional NOX source categories for RACT installation should be carefully conceived, and demonstrated to benefit air quality. It should be noted that positive impacts of NOX controls on ozone attainment is highly uncertain.

Ozone formation depends on the ambient air ratios of VOCs to NOX. Depending on the level of this ratio, it is entirely possible for reductions in NOX to cause an increase, not a decrease, in ozone formation. What makes this issue even more complicated is that the VOC to NOX ratio varies from nonattainment area to nonattainment area and even within a single nonattainment area. Therefore, while NOX controls may be appropriate in one section of the nonattainment area, that benefit may be negated by an increase in ozone levels in another.

Another important consideration is that NOX controls should not be required if there would be no impact on air quality, either positive or negative.

Models adequate to handle area-wide NOX issues exist and analyses can be made of individual or aggregated NOX controls. Given that NOX controls may have a negative impact on ozone air quality, precipitous action in imposing automatic NOX controls is particularly inappropriate.

IMPACTS

Under the S. 1630 language, a potential scenario could require a facility with two 500 HP engines (equivalent to approximately 100 tons per year of NOX), located 100 miles from the core nonattainment area (county), to install controls such as selective catalytic reduction. The capital cost for these controls would be roughly $36,000, with an annual operating cost, excluding capital recovery, of $24,000. However, the imposition of NOX controls at this facility and other qualifying facilities within the MSA/CMSA could have three possible outcomes: (1) no impact, (2) make air quality worse, or (3) improve it. While the cost per ton of NOX removed by these devices may be within acceptable ranges, there is a good chance that the expense would be wasted.

CONCLUSION/SOLUTION

ARCO recommends that automatic RACT for NOX not be mandated. While NOX controls may be appropriate in certain circumstances, careful analyses of local factors should determine if they are the most effective way to address ozone nonattainment. Such determinations would be best handled by the state. The state should be given the flexibility and authority, which it has under current law, to require RACT on NOX sources on a case-by-case basis.

We recommend §107 be changed in the following way:

Change line 3, page 218, to read, "and that have the potential to emit one hundred tons or".

After the word "compounds" on line 4, page 218, place a period (".") and delete the remainder of line 4 through line 15.

Insert after line 15, page 221:

> (3) Within two years of the date of classification, the state will determine, based on modelling and monitoring for each ozone nonattainment area, whether reasonably available control technology on sources that have the potential to emit 100 tons or more per year of oxides of nitrogen will result in a significant improvement in ozone air quality. Upon such demonstration, the state may, in those demonstrated ozone nonattainment areas, or portions thereof, require RACT on sources of 100 tons or more of oxides of nitrogen per year."

Delete lines 5 through 12, page 223.

O MARINE VESSEL LOADING AND UNLOADING

ISSUE

§107 calls for the development of control technique guidelines (CTG), within two years, for volatile organic compound (VOC) emissions from the loading or unloading of petroleum products for vessels.

ARCO supports the development of uniform emissions control standards for the loading and unloading of petroleum products from marine vessels, and in fact, we have been working with the U.S. Coast Guard to develop a uniform approach to controls. Our concerns with such emissions control standards are twofold: (1) vessel safety, and (2) uniformity of actual emissions control systems from port to port. We do not believe that the CTG process, as spelled out in S. 1630, is the correct vehicle for addressing vessel loading/unloading emissions controls.

Vessel safety - Onshore emissions are properly under the jurisdiction of the EPA. However, the only agency that has the capability, expertise and legal responsibility to ensure vessel safety is the U.S. Coast Guard. Therefore, the Coast Guard should have the primary role in both the design and enforcement of emissions control systems for vessels. Obviously, the EPA, in consultation with the Coast Guard, will determine the level of control that defines reasonably available control technology (RACT), but the local air management agency should be able to opt-in or opt-out of imposing such controls as they deem necessary in those areas where controls would be beneficial in solving pollution problems. Vessel enforcement, for safety reasons, should be left in the hands of the Coast Guard.

Uniformity of control systems - Petroleum cargo vessels engage in interstate or international trade. It is of paramount importance that they have a single emissions control set-up so that they can operate in any port. Therefore, the local agency should not be permitted to mandate different control measures.

CONCLUSIONS/RECOMMENDATIONS

The special requirements in dealing with emissions controls from vessels render the CTG process improper.

As an alternatve to the legislative language of S. 1630, we recommend the following:

On page 228 starting after "SELS.--" on line 24, delete everything down through line 5 page 229 and substitute the following language:

> "(1)MARINE VESSEL STANDARDS.--
>
> (A) Within four years after the date of enactment of this section, the Administrator shall promulgate standards applicable to the emission of volatile organic compounds from

loading of hydrocarbons onto marine tank vessels. In setting such standards, the Administrator shall apply reasonably available control technology and consider costs, any non-air-quality benefits, extent to which vessel emissions affect air quality, environmental impacts, energy requirements, safety factors associated with alternative control techniques and the impact on interstate and foreign commerce. In setting such standards as are applicable to equipment located on marine tank vessels, the Administrator shall obtain the concurrence of the Secretary of the Department in which the Coast Guard is operating.

(B) Any regulation prescribed under this section (and any revision thereof) shall take effect after such period as the Administrator finds (after consultation with the Secretary of the Department in which the Coast Guard is operating) necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period.

(2) Within six months after the date of enactment of this section, the Secretary of the Department in which the Coast Guard is operating shall issue regulations to ensure the safety of the equipment and operations which are to control emissions from the loading of marine tank vessels, under section 3703 of title 46 of the United States Code and section 1225 of title 33 of the United States Code.

(3) (A) The Administrator shall ensure compliance with the vessel emission standards prescribed under paragraph (1)(A), except that compliance of equipment located on marine tank vessels with the standards prescribed under paragraph (1)(A) shall be the sole responsibility of the Secretary of the Department in which the Coast Guard is operating.

(B) The Secretary of the Department in which the Coast Guard is operating shall ensure compliance with the regulations issued under paragraph (2).

> (4) Until the Administrator promulgates standards under this section, no State or political subdivisions thereof may adopt or attempt to enforce any standard respecting emissions from marine vessels.
>
> (5) After the Administrator promulgates standards under this section, no State or political subdivision thereof may adopt or attempt to enforce any standard applicable to equipment located on marine tank vessels promulgated under paragraph (1)."

The issue of vessel stack sources is not covered in Title I. We would be pleased to offer suggestions on the control of those types of emissions in nonattainment areas, as well.

AIR TOXICS

Overview

Our concerns with the impacts of the air toxics provisions on the petroleum industry are: (1) source categorization, (2) the definition of "maximum available control technology (MACT)," and (3) the determination of residual risk.

OVERALL IMPACTS

As background, Delta Management, a consulting group, under the sponsorship and with the cooperation of members of the American Petroleum Institute, estimated the potential cost of air toxics legislation on the petroleum industry. We would be pleased to provide you a copy of the report. The study found that the air toxics provisions of proposed legislation will be quite expensive.

Study background

While this study does not represent the exact provisions of S. 1630, it does represent an approximation of the costs of two different levels of control technology. We must emphasize, however, that if cost is no object, as required for "residual risk" controls in S. 1630, then the cost estimates in the API study may be substantially understated.

Two levels of control were postulated:

- Level I - Somewhat more stringent than Best Available Control Technology (BACT), but not as stringent as Lowest Achievable Emissions Rate (LAER).
- Level II - The more stringent level of MACT would be akin to Lowest Achievable Emission Rate (LAER) - the best control technology installed anywhere or even technology that has not been demonstrated, i.e., leakless valves, double seals on pumps, leakless flanges, vapor recovery on waste water systems, etc.
- In most instances, these two levels of control would be sequential, i.e. the two costs would be additive.
- While we have assumed that Level II is the best that can be done, we have not conducted health risk assessment studies to ensure that it would meet the 1 per 1,000,000 risk exposure level in all cases, as is required under the S. 1630 "residual risk" provisions for additional controls.

Study results

- API's study results for the two levels of control follow:

Capital Costs $billion	Level I	Level II	Total
Production	8.5	27.0	35.0
Transportation	.9	3.0	4.0
Refining	1.3	14.0	15.0
Marketing	4.3	9.2	14.0
Total	15.0	53.0	68.0
Annualized Cost	3.2	9.6	12.8

- The "total" figure may represent an extreme - an upper bound - that is not likely except under the worst of all cases [Level II controls are not anticipated in all cases].

Differences in assumptions between API study and the requirements in S. 1630 will be described in the discussion below on the issue of MACT and residual risk.

With the API cost study as background, we continue with a discussion of the three interlinked issues:

- **SOURCE CATEGORIZATION -- OIL AND GAS EXPLORATION AND PRODUCTION**

ISSUE

§301 (starting with line 5, page 327) requires that all categories of area sources that EPA finds presents a threat of adverse effects, either individually or in the aggregate, be subject to technology-based standards. Preliminary lists of source categories from EPA include oil and gas production, presumably because these sources have been aggregated. Nationally there are nearly one million oil and gas wells, and 200,000 production facilities, such as tank batteries and compressor stations. However, it is not correct to aggregate them since they are dispersed - one tank battery can be miles from the next. Unlike most of the other small sources on the list of categories, these sources are typically not found in densely populated areas. While ARCO generally supports the concept of technology-based standards, it is inappropriate for all exploration and production sources to be subject to expensive controls without a finding of significant risk to public health.

Many of the factors that define oil and gas exploration and production sources as low risk are acknowledged in the legislation, but these factors are only used for scheduling the writing of standards for source categories, not in initially choosing those categories.

IMPACTS ON OIL AND GAS EXPLORATION AND PRODUCTION

If virtually every emissions point source must be controlled, the impact on oil and gas exploration and production will be enormous. Additionally, the permits title would require that tens of thousands of these small area sources obtain permits.

Yet, the emissions from a typical oil lease, consisting of four wells and a tank battery, are quite low. Using EPA and California emission factors and EPA VOC speciation data, a reasonable estimate of benzene emissions from all the equipment on the lease would be from 50 to 100 pounds over an entire year. While oil and gas exploration and production are very low risk, the costs to control these sources are extremely high. According to the API cost study (above) for two levels of control, costs to oil and gas exploration and production could range from $8.5 billion to $35 billion. Moreover, if such costs are automatically imposed, there are potentially 29,000 U. S. oil wells that could be abandoned, or 143,000 barrels per day that would vanish from domestic oil production. The lost domestic reserves would be 500 million barrels. Regulation without justification may have several objectives, but to eliminate such a large segment of our domestic production is, indeed, foolish.

CONCLUSION/SOLUTIONS

We recommend that, prior to designating oil and gas exploration and production (SIC code 13) as a source category for control, Congress direct EPA to study the adverse effects (risks) of toxic air emissions associated with oil and gas exploration and production on public health. The study should include an analysis of: proximity of the operations to populated areas; the size of these populated areas and their background toxic constituent levels; the amount of emissions from individual oil and gas units; meteorology and dispersion as well as other factors. Provision should also be made to control any individual unit shown to pose an unreasonable risk to human health without waiting for the conclusion of the EPA study. In fact, industry is now beginning to investigate if any particular units may have a significant level of emissions.

We do not ask that oil and gas exploration and production be given special treatment in the event that our operations pose an unreasonable risk to human health. We believe, however, that sufficient justification exists to seriously question whether our exploration and production operations pose an unreasonable risk, and further, if the cost of control is automatically justified.

A finding can be commissioned by legislation and we recommend that the language in §301 be changed in the following way:

After line 15, page 377, insert the following new (q) and resequence the current (q) through (u) as (r) through (v),

"(q) Oil and Gas Exploration and Production. --
(1) The Administrator shall conduct a detailed and comprehensive study and submit a report to Congress on the adverse effects, if any, of toxic air emissions from equipment and activities supporting or associated with oil and gas exploration, development, or production of crude oil or natural gas (SIC Code 13) on human health. Such study shall include an analysis of:

(A) proximity of oil and gas operations to populated areas;
(B) population density of areas close to oil and gas operations;
(C) amount of emissions from individual process units;
(D) meteorology and dispersion modelling;
(E) demonstrated cases of health impacts from toxic air emissions from oil and gas operations;
(F) background constituent levels, and associated risk, in both heavily populated (core urban areas) and sparsely populated areas;
(G) current state and federal regulations addressing safety issues and air emissions from oil and gas operations;
(H) available and potential control technologies;
(I) costs/control efficiency/health benefits of controls;
(J) impact of new controls on the exploration for, and development and production of crude oil and natural gas.

(2) The Administrator shall prepare a summary of the findings of the study required under paragraph (1), a plan for research, development and demonstration respecting the findings of the study, and shall submit the findings and the study to Congress within three years after the date of enactment.

(3) Not later than six months after completion and submission of the study required in this subsection, the Administrator shall, after public hearings and opportunity for comment, determine if regulation of toxic air emissions from oil and gas operations is necessary and appropriate utilizing the results of the study. The Administrator shall publish his decision in

the Federal Register accompanied by an explanation and justification of the reasons for the decision.

(4) The Administrator shall transmit his decision to both Houses of Congress. However,

(A) if any individual unit is shown to pose an unreasonable risk to human health, such unit[s] may be subjected to control separately from this subsection on a case-by-case basis, and

(B) the same criteria specified in paragraph (1) will be used to determine that an individual unit poses such an unreasonable risk to human health."

O MAXIMUM AVAILABLE CONTROL TECHNOLOGY (MACT)

ISSUE

§301 (starting with line 15, page 329) requires the setting of standards for emissions control technology - generally described as Maximum Available Control Technology (MACT). While the Administrator is directed to take costs into account in setting up these standards, there is a seeming conflict with a later direction that MACT for new sources is to be defined as, "not less stringent than the most stringent emissions level that is achieved in practice;" and for existing sources as, "may be less stringent than for new sources... if [that new source] level is generally technically or economically infeasible.. and, considering, sequentially, the level of control achieved by existing sources in the category ..... beginning with the most stringent such level, establishes an emissions limitation which is generally feasible and assures the maximum total reduction in emissions for all sources..... a reduction of 90 per centum from uncontrolled levels is an appropriate benchmark."

With the seeming conflict in the definition, we are unclear on the required level of control. In our reading, the MACT standard for new sources would seem to fall somewhere between Best Available Control Technology (BACT - the best technology available considering cost and feasibility) and Lowest Achievable Emissions Rate (LAER - best technology without considering cost) depending on the single best control technology installation for any source in the category. Most likely, the standard imposed would be closer to LAER - i.e. control without regard to cost.

The MACT definition for existing sources is also unclear. We believe that it would also likely be close to LAER because, presumably, the effective date defining existing sources would be the date of enactment. Therefore, new sources prior to the date of enactment would qualify as existing sources for the purposes of defining MACT in this section. And, new sources prior to the date of enactment may well have been required to meet New Source Performance Standards which could have called for the use of LAER technology. While the "existing source" definition for MACT provides a "technically or economically infeasible" relief valve, the agency is directed to, "assure the maximum total reduction in emissions from all sources." Thus, MACT for existing sources is likely to be an extremely stringent level of control technology.

IMPACTS

The definition of the term "Maximum Available Control Technology" (MACT) is critical in determining both the operational and the financial impacts of the legislation on the petroleum industry.

Comparing the MACT requirement in S. 1630 with the assumptions used in the API industry cost study above, we conclude that S. 1630 is considerably more stringent than "Level I." If that assumption is correct, capital cost to the industry for the first round of MACT controls will be substantially greater than $15 billion, while annualized costs would be substantially greater than $3.2 billion.

From an operational standpoint, the bulk of these stringent requirements can be complied with, but there is little question that marginal operations will be eliminated. This is true for all segments of the industry and is spelled out, in particular, for the exploration and production segment under the comments above on "Source Categorization."

CONCLUSIONS/SOLUTIONS

While ARCO supports the concept of the imposition of technology-based standards for air toxics control, followed by an assessment of residual risk which would govern the second level of control stringency, the definition of MACT, for both new and existing sources should be tempered by cost and practicality. The resulting MACT would be somewhat more stringent than BACT - generally available controls now in use and, therefore, reasonably applicable. This level of control would offer substantial reductions in air toxics emissions, which, in many cases, will be sufficient to provide the necessary level of exposure protection to the population - the goal of this provision of the Clean Air Act amendments.

ARCO recommends that the definition of MACT in §301 be changed as follows:

On line 1, page 331, delete, "a source in the same category or subcategory," and substitute the following:

> "a representative sample of the best performing sources in the same subcategory (or category if not subcategories are designated),"

On line 2 and 3, page 331, delete, "and may be more stringent where feasible." and substitute the following:

> "and shall consider cost and feasibility factors."

On line 18, page 331, after the word, "levels" and before the word, "is" insert the following:

> "prior to emission levels promulgated by the 1970 Clean Air Act."

Delete paragraph "(A)" starting on line 7 and ending with line 15, page 333, and substitute the following:

> "emissions standards for not less than the ten categories or subcategories shall be promulgated not later than two years after the date of enactment of the Clean Air Act Amendments of 1989."

On line 19, page 333, change "three" to "four."

Starting on line 21, page 333, and ending on line 4, page 334, delete paragraphs "C" and "D" and substitute the following:

> "(C) Emission standards for an additional 25 per

centum of the listed categories and subcategories shall be promulgated not later than seven years after such date.

(D) For the remaining categories or subcategories listed under section (c) for which regulatory action has been initiated, the Administrator shall, within seven years after enactment, review and designate the additional categories and subcategories he finds, in his discretion, warrant additional regulation under this section. Emissions standards for the designated categories or subcategories shall be promulgated not later than ten years after enactment of the Clean Air Act Amendments of 1989."

o **RESIDUAL RISK VS UNREASONABLE RISK**

ISSUE

§301 (starting with line 10, page 336) directs the Administrator to evaluate remaining or residual risks to human health and the environment three years after the first round of MACT controls and to revise the standards within two additional years, if appropriate. "Appropriateness" is defined as protecting the most exposed individual (MEI) from an excess risk of one in one million chance of getting cancer. Most exposed individual is defined as being at the point of exposure 24 hours per day for 70 years - generally, but not necessarily, at the fenceline of a facility. Further, for known, probable or possible human carcinogens, two simultaneously applicable standards shall be established: one in ten-thousand and one in one million. Moreover, in the establishment of these "residual risk" standards, there will be, "No consideration of cost, cost-effectiveness, economic, energy, or other factors or technological feasibility...." The same mandates apply for hazardous air pollutants which are not carcinogens.

While we are unclear about the purpose of "two simultaneously applicable standards," the direction to the Administrator on the establishment of controls to protect against residual risk is both unambiguous and inflexible. The level of control measures that will result is beyond LAER because even technological feasibility is ignored.

While we agree with imposing additional controls if the first level MACT is not sufficiently protective, we take strong issue with two points - the ramifications of control standards established with a fixed unit risk exposure value in all cases, and the implications of explicitly eliminating cost or technological considerations. Such an approach is predicated on the notion that we can create a riskless society and still enjoy all the benefits of the most highly developed industrial economy that has ever existed. While we would agree that this is an ideal goal, we do not believe that it is achievable in practice. We do not argue against the substantial control of air toxics - only against the attempts to guarantee a riskless state of conditions, however desirable.

But even if a riskless residual risk approach were adopted, there would be gross problems with its implementation. Witness the experience to date in air toxics regulations under Section 112 of the Clean Air Act - the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for benzene.

Airborne contaminant risk assessment methodology can be broken down into four components: (1) emissions estimation, (2) ambient air concentration estimation, (3) exposure estimation, and (4) potency estimation.

Emissions Estimation - Emissions can be either directly measured or estimated by the use of appropriate factors. EPA has tabulated emissions factors for a wide variety of processes in their publication AP-42. In general, they are conservative in that they tend to overestimate the actual emissions - by a factor that varies between 2 and 6.

Ambient Air Concentration Estimation - Air quality models are used to estimate concentrations of emitted species as a function of local meteorology and topography. Generally, the models overpredict the concentration; they also have no skill in predicting the time behavior of the concentration. Thus, one cannot predict with any accuracy the actual concentration of a species at a given point under a specific weather condition. EPA has established a set of "regulatory" models all of which are conservative; i.e. they overpredict to insure a reasonable safety factor in estimating concentrations, usually by a factor of 3 to 10.

Exposure Estimation - The current default methodology is to assume that the "maximally exposed individual" is exposed at the point of maximum concentration for 24 hours a day for a period of 70 years. This assumption does not take into account:

- The fact that the majority of the population spends over 70% of their time indoors.
- The fact that we live in a mobile society so that most people are exposed to a variety of both natural and anthropogenic pollutants.
- The fact that the relationship between outdoor and indoor concentration is highly variable and dependent on the chemical species of concern.
- The fact that few, if any, people will actually be exposed at the precise location used in the exposure estimation.

Moreover, the MEI concept usually results in an exposure overprediction with a safety factor in the range 10 to 15.

Potency Estimation - How toxic chemicals may act in humans is, at best, poorly understood. The majority of chemicals listed as "carcinogenic" have been so identified by animal studies. These studies use high doses with the assumption that total cumulative dose is the critical variable. The high dose data is then extrapolated to low dose rate using a linear model simplification. Due to the uncertainty of the method, only the most conservative estimators, with built-in safety factors that vary from 100 to 1,000, are used to extrapolate from animals to humans.

If we multiply all of the safety factors that have been built into each step along the way, the combined safety factor may be as low as 6,000 or as high as 750,000. Thus, the one in one million unit risk value required in S. 1630 for the establishment of control standards, in application, will be many orders of magnitude more protective than the risk standard envisioned by the bill. Even using a safety factor of 1,000 - which is a factor of 6 lower than the least conservative [combined] safety factor we would expect - the level of protection goes to **one in one billion** instead of one in one million.

In practice, S. 1630 will drive the manufacturing and processing industries to foreign countries.

In particular,

- We oppose the concept of using only the most exposed individual (MEI), because its use results in a gross over-estimate of exposure - a seventy-year lifetime exposure. EPA's own Science Advisory Board has gone on record stating that EPA's definition of the MEI is "overly conservative and consequently unrealistic." EPA should develop the best individual risk exposure estimate on the basis of human behavior analysis and activity patterns which includes time spent indoors/outdoors, in the workplace, relocation patterns and the like.

- We believe that if S. 1630 uses the most exposed individual concept, which overestimates exposure, it should do so in conjunction with more reasonable and attainable standards of acceptable risk. For example, in the recent NESHAPS rule for benzene, EPA rejected arguments against the use of the MEI, but conceded that MEI over-estimates exposure and risk and thus adopted a one in ten thousand unit risk value instead of a one in one million for most of this rule.

- Present EPA risk estimates are based on linear models using upper-bound estimates. EPA is aware that this approach over-estimates risk. EPA's unit risk standard should be based on biologically-relevant, real-world risk assessment models, as well as accurate and up-to-date data. While Section 301 (line 22, page 378) does call for a study of risk assessment, the section does not say that this information should be used in the development of standards, only reported.

- While we applaud the Agency's support for the development of more accurate models and methods to assess risk, the Agency is slow to use these improvements in practice. For example, during the recent rulemaking on toxic air pollutants (NESHAPS), EPA used a 1985 risk assessment on benzene which was considered even by EPA to be "preliminary and incomplete" while they rejected more recent information and data from industry and the open literature.

In summary, the proposed residual risk requirements of S. 1630 are overly stringent, inflexible, and result in levels of protection that are thousands or even hundreds of thousands times more protective than those envisioned in the bill.

IMPACTS

The potential impacts of the residual risk requirements are dramatic. According to an EPA study, if a one in one million unit risk value for benzene were to be imposed, all of the refineries and chemical plants in a sample size of 131 plants (for which EPA had emission data) would have to cease operation. It should be pointed out in arriving at this conclusion, EPA was using their ultra-conservative risk assessment methodologies - as described above.

From a cost impact standpoint, we refer back to the API cost study. It is entirely likely that the imposition of one in one million residual risk standards, without consideration of cost or technology, goes substantially beyond the postulated API Level II controls [the most stringent control levels known or unknown, but possible]. We have no idea of real cost, except to estimate that the combined capital costs for the petroleum industry would increase between a factor of 2 to 10 beyond those estimated - resulting in a cost of $150 billion to $680 billion - perhaps even more, we simply have not evaluated that scenario. If new standards without regard to real benefit or cost are adopted, we will have effectively exported our refining capacity to foreign countries.

CONCLUSIONS/RECOMMENDATIONS

We recommend that the legislative language in §301 be modified to be along the lines of the Administration bill which calls for "phase two" standards of "unreasonable risk."

Such changes would be as follows:

On line 10, page 336, change the word, "three" to "seven."

Delete paragraph (C) starting with line 13, page 337, and ending with line 16, page 338, and substitute the following new paragraph (C):

> "If the Administrator finds after such evaluation, that the category or subcategory, or portion thereof, after application of the prescribed standards in section (d), presents an unreasonable risk to public health taking into account the cost and technical feasibility as well as the heath risks of such standards, he shall, within two years after completion of such evaluation, promulgate standards to protect adequately against such

risk."

In addition, the language requiring the Agency to conduct a risk assessment study should be supplemented.

In §301, line 22, page 378, after "ASSESSMENT --" and before, "The Administra-," insert "(1)".

At the end of line 24, page 379, add the following language,

"In those cases where the uncertainty in the net risk estimate is found to be greater than a factor of five (5), due to any cause, the Administrator shall identify the research necessary, and the estimated costs thereof, to reduce the uncertainty to within a factor of five (5). The research shall address the biological/biochemical mechanisms of the adverse health effects, the relation between exposure and effect, as well as the mechanism(s) of dispersion and route of human exposure. For each finding, the Administrator shall convene a special panel consisting of representatives of the industry affected, independent experts, and experts from the Agency. The panel shall review the basis for the report and shall determine whether the risk to human health can be realistically (accurately) estimated. If the panel determines that the results are ambiguous or would result in an overall uncertainty greater than a factor of ten (10), the administrator shall either:

(A) Have that research necessary to reduce the uncertainty to a factor of five (5) conducted, or
(B) Make a finding that the results represent the best state of the art and publish a methodology which uses the available data and which uses the most likely estimator of the effects and a safety factor sufficient to protect human health. In no event shall such a safety factor, taken in aggregate with all aspects of risk analysis, be greater than 20.

(2) Within a period of five years after the completion of a study, and each five years thereafter, the Administrator shall update the risk assessment studies in (s)(1) above and complete the updated study within a period of 12 months.

(3) Upon completion of the each risk assessment study, the Administrator shall revise the standards developed in (e)(7), (f), and (g)."

PERMITS

ISSUE

Title V (starting on line 7, page 495) mandates that the Administrator set minimum requirements for use by local agencies in permitting facilities to be constructed, modified and operated under the Clean Air Act. Included are: a new emissions fee structure; five year permit life; 90 day review by the Administrator; submission of the permit to contiguous states for comment/approval/disapproval; and public hearings on permits.

A federally directed uniform permits/fees program is simply not necessary. State and local agencies now have permit systems both for construction and operation. Permits are the basis for fee collections which are used to fund local air quality management district programs.

A five year permit life also creates uncertainties. Ordinarily, construction on major projects can take from two to three years, and with a five year permit life, that leaves two to three years of operation on the permit. And then the entire project is subject to a new permit application. The economic uncertainty created provides a strong disincentive to plan for and make major construction commitments.

In one of the districts in which we operate, it can sometimes take one or more years to get a permit. A 90-day Agency review does not seem plausible.

The requirement for contiguous state approval for all permits will be burdensome to both the applicant and the state/local agencies.

IMPACTS

A federal permitting system overlay on the current local system would make what is now a difficult task even more difficult. We see more road blocks in trying to develop and manufacture products like EC-1 that are environmentally preferable to the products we formerly manufactured.

CONCLUSIONS/RECOMMENDATIONS

A new federal overlay on the current local permitting system is simply not necessary.

We recommend deleting Title V in its entirety by starting with line 7, page 495 and deleting everything through line 4, page 515.

COORDINATION BETWEEN NONATTAINMENT AND AIR TOXICS TITLES OF THE BILL

ISSUE

The coordination between Title I (nonattainment) and Title III (air toxics) of the bill is not clear. It appears that volatile organic compound (VOC) emissions reductions required under Title III would not count as offsets in Title I of the bill. If such reductions were VOC's and, therefore ozone precursors, we fail to see the logic in not permitting these reductions to be used either as offsets or as a part of VOC reduction requirements in other parts of Title I.

GENERAL CONCLUSIONS

Finally, I would like to summarize several points.

While new clean air legislation should be tough, it also should (1) allow industry to accomplish clean air goals, and (2) allow us to also update our technology and processes. If we do not have that flexibility, we cannot be responsive to changes in consumer demand or compete in world markets, much less improve the environmental performance of our products.

It is our judgement that if S. 1630 is enacted in its current form, the restrictive requirements in the nonattainment, air toxics and permitting titles will have a number of results:

- They will severely hamper, if not destroy, our ability to develop and manufacture new products - that are environmentally superior;
- They will freeze the status quo of our technology and stifle our ability to innovate;
- They will eliminate the necessary flexibility to operate in the most economic way possible.
- They will decrease the ability of the domestic petroleum industry to explore for and produce oil and gas;

The potential consequences are quite clear. The production and manufacture of petroleum resources - both raw materials and finished products - will be driven out of the U.S. to foreign countries. We have already started down that path, but S. 1630 - as written - will accelerate the process.

One of our chief concerns with the nonattainment provisions is that they create a contradiction. They mandate new products, while restricting operations and eliminating the flexibility needed to obtain permits to make those changes - either voluntarily or involuntarily. These restrictions even apply for changes that would improve air quality - such as the manufacture of reformulated gasoline.

Our chief concerns with the air toxics provisions are twofold:

- Our exploration and production sector could be automatically subject to costly controls even though the remoteness of their operations may pose little, if any, threat to public health,
- The stringent and inflexible requirements of "residual risk" - based controls for refineries and chemical plants, coupled with an overly conservative enforcement by the EPA could - according to the Agency - shut down all refineries and chemical plants in the U.S.

In our view, the province of government is to set standards and it is industry's province to determine the best way to achieve the standards. Innovation and change are the key to success, not only for us, but for the nation as well. The best way to make the clean air program work is to harness industry's creative talent and resources in solving these problems. Legislative solutions that limit options that would achieve favorable results deprive the nation of the benefits of creativity and innovation and every effort should be made to liberalize the methodology while setting standards to achieve national goals.

Let me again express ARCO's appreciation for allowing us to share our views with the Senate Energy and Natural Resources Committee on the impacts of S. 1630 on the petroleum industry.

Finally, if it would be helpful to the Committee to respond to further questions or in working with the Staff to develop conforming amendments, we would be pleased to do so.

James S. Morrison
Executive Vice-President
Atlantic Richfield Company
January 25, 1990

The CHAIRMAN. Thank you very much, Mr. Morrison.

Next we will hear from Dr. Charles Goodman, Vice President for Research and Environmental Affairs of The Southern Company.

STATEMENT OF DR. CHARLES H. GOODMAN, VICE PRESIDENT, RESEARCH AND ENVIRONMENTAL AFFAIRS, THE SOUTHERN CO.

Dr. GOODMAN. Thank you very much. I would like to thank you for this opportunity today to present the views of The Southern Company on the air toxics provisions of S. 1630. We have submitted also written testimony concerning the provisions for the committee's consideration. My chief purpose this morning, therefore, is to focus briefly on the fundamental changes that we believe title III of S. 1630 would make in the way that section 112 of the existing Clean Air Act treats emissions from electric utility boilers.

This drastic restructuring of section 112 would impose enormous cost burdens on electric consumers, burdens that are especially punishing to the poor and those on fixed income as you talked about yesterday in the acid rain discussions. That would raise energy costs for American industry and, I believe, make us less competitive in the world markets.

Our customers are going to have to bear the brunt of these increases. It would disrupt fuel markets, and I think we will come back to some discussions on how we believe that will happen with respect to coal in particular and will modify the ways we could use supplies of fuels in this country.

In light of available scientific evidence, it would do all of this harm to, I believe, our economy and our people with very little appreciable health benefit.

To see how drastic this change would be, we must look back at what Congress had in mind when the existing section 112 was adopted and the way in which EPA carried out this intent of Congress. The legislative history of the Clean Air Act of 1970 shows clearly that Congress recognized a significant difference between admissions from industrial and chemical processes and the trace emissions that are incidental to the general combustion processes of fossil fuels. In the case of electric generation, trace materials that are designated as hazardous by S. 1630 appear but in very small quantities.

As enacted, section 112 gave EPA broad discretion based on risks to human health to determine which substances warranted regulation. The wisdom of this flexible approach has been confirmed in the years since 1970. To give an example, even though Congress made clear its intent was not to regulate trace emissions from sources like power plants, EPA has evaluated such emissions for various substances. In each case the agency found that the health risk posed by these traces was very small or not warranting regulation.

In these evaluations the agency used very conservative risk assessment procedures. For example, in the radiological procedures EPA assumed that individuals were wearing no clothes, lived outdoors at the point of maximum exposure, ate food that was subject to maximum exposures, and all this happened over a 70-year period constantly.

Even with these and other conservative assumptions related in the analytical procedures, the agency found the predicted hypothetical risk of contracting a fatal cancer to be on the par in this case of the risk incurred by eating one peanut every 250 days with an FDA-permitted level of aflatoxins, a naturally occurring carcinogen. Now that is not meant to be a joke. The point is that it is a very small risk compared to other things.

We have talked about these two. Let us mentioned the others. The two additional incidence of cancer in some of the other studies out of a population of 250 or 240 million people, we first have to ask is it even significant? We ask a lot of times is it real. Is it significant? Generally, we believe it is not.

Anyway, we believe that Title III has taken away the flexibility of EPA to do these kinds of analysis. The issue is a real world economic issue that can be measured in billions of dollars, a cost that is completely out of proportion to any benefit that can be claimed in light of the scientific data. For our company, the Sun Electric System, which represents five electric utilities in the southeast, it would result in capital expenditures of something like $12.5 billion for us, for a 25 percent rate increase. Now that includes the acid rain provisions. Basically it triples the cost of compliance with the acid rain provisions for us.

Basically it means we are going to put bag houses in something similar to desulphurization in our facilities. We believe this maximum available control technology is by category, it is a top-down approach, and we can talk about flexibility the way it is written, but it is going to be very difficult for EPA.

My attorneys advise me the way it is written in the committee's report for EPA not to go to those extremes, even though our current electrostatic precipitators and equipment may do a very adequate job.

The CHAIRMAN. Would you tell us why the toxics provisions renders the sulphur, the acid rain provisions redundant and unnecessary?

Dr. GOODMAN. If you look at the categories of air toxics, there are those that are in particulate form, and that is where you talk about a bag house potentially collecting cadmium and some of those materials. Others like the chlorides and potentially others on the list I think we make a mistake if we just focus on the chlorides that are in a more volatile form, gaseous form, to treat those or collect those.

We are not even always sure we have the available technology, but our process engineers basically say that the equipment is going to look very similar to flue gas desulphurization equipment. We are going to have to cool that flue gas, we are going to have to wash it, maybe a water scrubber instead of limestone, but we are going to have to do that process.

If you are in a utility business and you are going to have to build that equipment anyway and you are concerned about not just about low-sulphur coal and its chlorides, but any coal having various parts of these trace constituents, you just as well build it to do scrubbing too and take advantage of the lowest cost coal you can find. And for us that, in most cases, will be high-sulphur, the most local coal we can find.

So, I think that is the way we are going to talk about having an impact on the coal markets.

It is also going to raise costs significant, which is going to imply other fuels, be it gas or nuclear or other options are going to become something we are going to consider more often.

The CHAIRMAN. That means you have got to always scrub?

Dr. GOODMAN. That means we have got to always scrub under our interpretation of what EPA would have to do to us to determine maximum available control technology for the category of utility boilers.

Dr. GOODMAN. Or for retrofit of utility boilers.

Senator FORD. Are you saying to us now this ace group with the low-sulphur coal, that group is whistling Dixie? That with your position under this legislation that low-sulphur coal is going to be your best buy, and you are just going to go ahead and scrub? Am I correct in that assumption?

Dr. GOODMAN. Under our acid rain provision analysis, we have a balance between using the low sulphur coal and scrubbers on the 20,000 megawatts or so of coal-fired power plants we have.

If we have these air toxics provisions—chlorides is an issue that has been discussed a lot—we are going to put scrubbers on everything anyway, then paying those additional premiums for high-sulphur coal that we expect would not be worth it—I mean for low-sulphur coal—would not be worth it.

Senator FORD. That is what I wanted to get to. Thank you.

Senator NICKLES. Could I follow up?

So, you would be buying just low-sulphur coal or you would be able to maintain high-sulphur coal?

Dr. GOODMAN. We would probably be just buying high-sulphur coal because there is a cost premium for most low-sulphur coal, and you would not want to pay that if you have already put those dollars into buying the scrubber.

I think basically the question we keep coming back to is what would Americans, consumers and taxpayers get for this enormous price? We think that is the big question with that degree of uncertainty. And when I say uncertainty, I mentioned earlier the risks that you are predicting, these—$\frac{8}{10}$ of an increased cancer, 1.5 to—in a population of 240 million people, and we think that is a very uncertain—that is not the kind of risk that the medical community generally look at at the Center for Disease Control or the broader health community.

With that degree of uncertainty with the lack of scientific evidence suggesting that trace emissions from utility power plants pose a public health risk, the utility industry believes that changing section 112 to mandate regulations of utility power plants is unwarranted.

I think your gentleman's question is what is the alternative. I think the alternative has been brought up several times this morning and yesterday, and that is the clean air proposal of the administration section or bill 1490.

They have included a provision requiring EPA to perform a study of any public health hazards that might reasonably be anticipated to result from trace emissions from utility boilers. And the administration proposal calls for the agency to report its findings within—after three years of enactment of the bill.

We definitely support that approach. I would only say to you that the thing that we are pushing is making sure that that study really is a high quality health study, something similar to developing criteria documents that we now have when we look at other pollutants that EPA regulations, something that is reviewed by groups like the Clean Air Science Advisory Councils, so that we really do have public input not only from companies, but the public, but also the medical to really decide what risk is really there and what is worth protecting.

I think finally—well, the point is short of excluding utilities, which we basically think could have merit, we would strongly ask that you gentlemen support the proposal the administration has made for study on utility boilers.

In addition, our company does have a strong commitment to nuclear power plants. We, therefore, want to be on record to support the provisions of sections or bill 1630 which require excluding radioactive materials regulated by the NRC under the Atomic Energy Act from additional regulation under the Clean Air Act.

We think basically EPA and NRC both support this. It is a matter of just being more efficient with resources, not being redundant and causing problems between these agencies.

In closing, Mr. Chairman, I would like to thank you and the committee for this opportunity to give my comments, and I would be glad to try to answer any of your questions. Thank you.

[The prepared statement of Dr. Goodman follows:]

TESTIMONY OF DR. CHARLES H. GOODMAN
OF SOUTHERN COMPANY SERVICES
ON THE AIR TOXICS PROVISIONS OF
S. 1630, THE CLEAN AIR ACT AMENDMENTS OF 1989,
BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

January 24-25, 1990

I. Introduction

Mr. Chairman and Members of the Committee, I appreciate the opportunity to testify before you today to present the views of the Southern Company on the implications of the air toxics provisions of S. 1630 for the electric utility industry.

The Southern Company is the parent firm of one of the nation's largest electric utility systems. Through five operating companies, this system serves more than 11 million people in the Southeast -- including large portions of Alabama and Georgia, plus parts of Florida and Mississippi.

My position is that of vice president for research and environmental affairs of Southern Company Services -- a subsidiary that provides specialized engineering, technical, and professional services to the parent firm and the companies that comprise the system. My organization is responsible for various clean coal related research programs which include four "innovative clean coal" technology projects.

The activities for which I am responsible include power plant and engineering research and environmental assessment. I also represent the Southern electric system in several industry organizations that provide environmental and technical data to federal regulatory agencies and congressional committees. I hold master's and doctoral degrees in engineering from Tulane University, and my work has centered on research and environmental issues related to coal utilization.

II. Statutory Overview

Title III of S. 1630, the Clean Air Act Amendments of 1989 (ordered reported by the Senate Environment and Public Works Committee on November 16, 1989), would restructure existing § 112 of the Clean Air Act, which provides for Environmental Protection Agency (EPA or Agency) regulation of hazardous air pollutant emissions.

Existing § 112 requires EPA to list as a "hazardous air pollutant" any "air pollutant to which no ambient air quality standard is applicable and which in the judgment of the Administrator causes, or contributes to, air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness." 42 U.S.C. § 7412(a)(1). Once EPA lists a substance as a hazardous air pollutant, the Agency then must establish an emission standard for the pollutant which provides "an ample margin of safety to protect the public health," unless the Administrator subsequently determines that the substance is clearly not a hazardous air pollutant. 42 U.S.C. § 7412(b)(1)(B).

Congress enacted § 112 to provide for regulation of a limited number of substances considered to be hazardous and gave the Agency broad discretion to determine which substances warranted such regulation. Title III of S. 1630 would fundamentally restructure § 112. It would require the Agency to list 191 or more substances as hazardous air pollutants and to regulate emissions of those substances through an initial technology-based regulatory scheme to be augmented by a subsequent standard based on potential health risk.

Under the bill, EPA must establish a list of sources for each substance. Any stationary source which emits 10 tons per year or more of any one listed substance or 25 tons per year or more of any combination of listed substances would be considered a "major source." EPA must set an emission standard for all major sources which requires the installation of maximum achievable control technology (MACT).

If, after installation of MACT, a significant predicted risk remains, EPA must promulgate health-based standards five years after initial promulgation of the MACT standard. For non-carcinogens, EPA must set standards at a level that provides an ample margin of safety to protect the public health. For potential carcinogens, the bill sets out two "residual risk" standards, for which the Agency may not consider emission control costs. Sources must meet a standard that would eliminate all lifetime risks of contracting cancer greater than 1-in-1,000,000.

Sources which demonstrate that this standard is not achievable may receive an exemption, but will be subject to an alternative standard which would eliminate all lifetime cancer risks greater than 1-in-10,000.

III. Summary of Testimony

Several substances listed in S. 1630 are naturally present in trace amounts in fossil fuels. Power plant emissions of these trace substances fall into two major categories: solids in the fly ash portion of the flue gas (e.g., manganese and nickel) and trace materials vaporized by high boiler temperatures (e.g., hydrochloric acid). Despite extensive regulation of air emissions under the Clean Air Act, utility power plants may still emit trace concentrations of these substances which, due to the large amount of fuel burned, could nevertheless exceed the arbitrary 10- and 25-ton threshold limits for regulation set without any scientific foundation in S. 1630. For example, a 1,000 megawatt plant operating at a nominal 60 percent capacity factor would consume approximately 2,250,000 tons of coal in a year.

The stringent Clean Air Act regulations already in place control utility power plant emissions so that, in most cases, over 99 percent of the particles in the exhaust gas are removed. Not surprisingly, when EPA has considered regulating substances under § 112 of the Act that power plants emit in trace amounts, the Agency has found in every case that the minimal risk to public health did not warrant further regulation.

In recognition of this fact, the Administration included in its clean air proposal (S. 1490) a provision requiring EPA to perform a study of the public health hazards reasonably anticipated to occur as a result of hazardous air pollutant emissions from electric utility steam generating units and to report its findings to Congress within three years of enactment. Under this provision, EPA could not impose § 112 regulations on electric utility plants unless the Agency found such regulation appropriate and necessary after considering the results of the study. The House Energy and Commerce Subcommittee on Health and the Environment has included this provision in its clean air legislation (H.R. 3030) as well.

In light of the lack of scientific evidence suggesting that trace emissions from utility plants pose a public health risk, the electric utility industry believes that mandating § 112 regulation of utility power plants is unwarranted. Short of excluding electric utility plants from regulation under the revised § 112 program, the Senate should include the Administration's study provision in S. 1630.

In keeping with this provision, we wish to express support for the provision of S. 1630 which would exclude radioactive materials regulated by the Nuclear Regulatory Commission (NRC) or an Agreement State under the Atomic Energy

Act from additional regulation under the Clean Air Act air toxics program. In adopting this provision, the Senate Environment and Public Works Committee recognized that EPA and NRC regulation of these emissions under the Atomic Energy Act is extensive and that any further regulation pursuant to the Clean Air Act would be unnecessarily duplicative and would potentially conflict with NRC requirements.

IV. Trace Emissions from Utility Power Plants

As noted above, electric utility power plants burn fossil fuels containing trace amounts of substances listed in S. 1630, which are emitted into the air upon combustion. Because of the proportionally small quantities of these substances and the absence of monitoring techniques to measure this minuscule portion of the gas stream, it is extremely difficult to estimate the amount actually emitted. Moreover, trace elements in coal vary widely. For example, according to an April 1989 study by EPA ("Estimating Air Toxics Emissions from Coal and Oil Combustion Sources" EPA-450/2-89-001), the range for mercury in subbituminous coal in North America is 0.01 to 8.0 parts per million (ppm). Similarly, nickel content ranges from 0.32 to 69 ppm, while the range for chromium is .54 to 77 ppm. This wide variation also makes predicting trace emission levels with any degree of accuracy extremely difficult.

What is known is that these substances are released in infinitesimally small concentrations. For example, emissions of hydrochloric acid from the combustion of coal at the low range of chloride content (5.25 ppm) at a typical 500 megawatt coal-fired boiler most likely would exceed the 10-ton/year threshold. Nonetheless, the resulting emissions would represent only 0.3 parts per million, or 0.00003 percent, of the gas stream. These already small concentrations, once dispersed into the atmosphere, result in extremely limited exposure to the surrounding population, which explains why EPA has found a negligible health risk associated with utility emissions of these substances to date. Unfortunately, by establishing arbitrary threshold emission amounts which lack any scientific foundation, S. 1630 would subject the electric utility industry to regulation regardless of the actual public health risk presented.

V. Minimal Health Risk Associated with Utility Emissions

In enacting § 112, Congress was concerned with a "limited number" of "extremely hazardous or toxic" substances. Congress made clear in the legislative history that the section was not intended to apply to general combustion processes. In fact, the Senate debate on the 1970 legislation enacting § 112 reveals that Congress expected EPA to recognize "the fact that trace materials may occur as impurities in many types of combustion" and that § 112 "would apply to primary producers of hazardous materials rather than to general combustion processes in which these materials appear as pervasive but in almost immeasurably small quantities."[1]

Notwithstanding Congress' observation in enacting § 112 that the section was not directed at trace emissions from sources like power plants, EPA has evaluated trace emissions from power plants with respect to a number of the substances listed, or considered for listing, under § 112. In each case, the Agency found the health risk posed by these emissions to be minuscule and not warranting regulation. EPA also has evaluated the cumulative health risk posed by exposure to a combination of a number of these substances. EPA again determined that the health risk was minuscule. In other words, all EPA evaluations to date confirm the judgment reflected in the legislative history of § 112 that trace emissions from combustion at power plants are not appropriate targets for regulation under § 112.

Moreover, in these evaluations, EPA used very conservative risk assessment procedures reflecting conditions that will not be found in the real world. For example, EPA assumed constant exposure to a substance for 70 years with the individual wearing no clothes, living outdoors at the point of maximum exposure, and eating food subject to maximum deposition of these substances. Even with these assumptions, the predicted hypothetical risk of contracting a fatal cancer was equivalent to the risk an individual assumes in eating one peanut with the FDA-permitted level of aflatoxins (a natural carcinogen) once every 250 days.

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[1] A Legislative History of the Clean Air Act Amendments of 1970, The Environmental Policy Division of the Congressional Research Service of the Library of Congress (Comm. Print, Senate Comm. on Public Works 1974) (Serial No. 93-180), page 289.

VI. Unpredictable Effect on Energy Supply and Cost

If coal- and oil-fired power plants are subject to the full range of regulation envisioned in S. 1630, the impact on various fuel markets in the U.S. could be substantial. For at least some of the substances listed in the bill, no control technology has been demonstrated. Thus, to control certain emissions, utilities would be forced to switch fuels based on the content of these substances -- which, as noted earlier, can vary widely.

The variability of these substances significantly complicates the process of determining the effect of S. 1630 on U.S. fuel markets. Nonetheless, any degree of fuel-switching would have a substantial economic impact on many regions of the country and could result in significant unemployment. For example, some of our lowest sulfur coals in the West are high in chloride content. Regulation under S. 1630 could force utilities to stop using these coals.

On behalf of the electric utility industry, I urge this Committee to assess the potential impact of S. 1630 on U.S. fuel markets and supplies before the imposition of § 112 regulations on utility power plants. Enactment of a study provision like that included in S. 1490 and H.R. 3030 would afford this Committee, in coorperation with EPA and the Department of Energy, sufficient time to assess this impact and to avoid potentially massive disruption in U.S. fuel markets.

VII. Substantial Economic Burden on Utilities and Ratepayers

As noted earlier, particulate controls on electric utilities already limit emissions of a number of substances on the list. Options for further reducing emissions of these substances are limited and extremely costly. Without further substantive evidence of a known health risk, imposition of this economic burden is unwarranted and would impose substantial rate increases on electric consumers.

According to a 1986 study by EPA of coal and oil combustion, retrofitting existing utility coal-fired plants with advanced particulate controls (baghouses) would cost almost $4 billion annually. "Coal and Oil Combustion Study Summary and Results" External Review Draft, September 1986, pp. II-3, VIII-4. Using its excessively conservative risk assessment techniques, EPA estimated that this expenditure would result in a reduction in theoretical cancer incidents of 0.8 nationwide per year (from

1.4 incidents to 0.6 incidents annually) in a population of 240 million people. This risk estimate is so small that it has no meaning scientifically.

To put this in perspective, the cost imposed on utility consumers (the majority of whom are taxpayers) would be more than 60 times the amount allocated for cancer prevention and control[2/] and almost 4 times the amount expended on cancer research[3/] by the National Cancer Institute in 1986, the year EPA developed its cost estimate for retrofitting coal-fired plants. These massive and disproportionate expenditures would be made to avoid less than one theoretical incident of cancer.

For a number of substances listed in S. 1630, no known control technology has yet been demonstrated. For example, emissions of trace substances in volatile form from fossil fuel fired power plants are not controlled anywhere in the world today. While some volatiles could be controlled through the use of costly wet scrubbers, the benefits of such controls are wholly speculative at this time. S. 1630 nevertheless could lead to standards that would impose controls achieving 90 percent removal of volatiles at sources that exceed the thresholds.

[2/] In 1986, the National Cancer Institute expended $63.7 million for cancer prevention and control. National Cancer Institute Budget Office.

[3/] In 1986, the National Cancer Institute spent $1.011 billion on cancer research. National Cancer Institute Budget Office.

This could mean every power plant in the country would have to install some form of wet scrubber or, if possible, switch to a fuel supply that was extremely low in chlorides and other substances on the list that are volatile upon combustion. In light of the fact that emissions are already negligible and that no known adverse health effects are associated with these emissions, the astronomical costs of installing controls for volatiles or initiating massive shifts in fuel supply would place an enormous and unnecessary burden on utilities and electric consumers.

While all of the available data on trace emissions from power plants show extremely small risks, the costs of available control technology are staggering. According to our estimates at Southern Company Services, full compliance with both the acid rain and air toxic titles of S. 1630 would result in a capital expenditure of $12.5 billion and a rate increase for electric consumers of 25.1 percent. (These figures assume the installation of wet scrubbers and baghouses on all plants.) This is triple the cost of compliance with the acid rain provisions alone. Thus, the financial impact on consumers, particularly low-income households already burdened by energy costs, would be very serious.

VIII. Duplicative Regulation of Nuclear Power Plants

While S. 1630 could subject utility coal- and oil-fired plants to unnecessary regulation under the new § 112 program, the Senate Environment Committee did recognize that such regulation should not extend to nuclear power plants. Section 303 of S. 1630 would ensure that nuclear power plants are not regulated under § 112 by excluding radioactive materials regulated by the NRC or an Agreement State under the Atomic Energy Act (AEA) from the definition of "air pollutant" under the Clean Air Act. Thus, in the future the sole regulatory authority for such emissions would be derived from the AEA. The electric utility industry strongly supports adoption of § 303, which also won the endorsement of both EPA and the NRC during the Senate Environment Committee's deliberations.

The industry supports the provisions of § 303 because it continues a regulatory program, already in place for more than 30 years, that combines a technical and health risk approach to radionuclide emissions and that provides protection to public health with an ample margin of safety. The first regulations restricting emissions from NRC-licensed facilities were issued by the Atomic Energy Commission (the predecessor to the NRC) in 1957. Since that time, the regulations have been updated to account for advances in the understanding of health impacts of exposure to low levels of ionizing radiation, and to ensure that power plant emissions are kept "as low as reasonably achievable" (known as the ALARA principle).

Currently, the International Council on Radiation Protection and, in the United States, the National Council on Radiation Protection have determined that an individual should not be exposed, on an annual basis, to more than 100 millirem of radiation above natural background levels.

EPA was given the authority to adopt general environmental standards for radiation protection (under the authority of the AEA) pursuant to Reorganization Plan No. 3 of 1970, which created the Agency. EPA promulgated regulations in 1974-77 (40 C.F.R. Part 190) requiring the entire uranium fuel cycle (from the milling of uranium, to enrichment, to fuel fabrication, to the burning of fuel in reactors) to keep the exposure rate to the public to radionuclide emissions to no more than 25 millirem annually.

The NRC, in turn, updated its emission regulations in 1975 when it promulgated Appendix I to its Part 50 regulations, which established design criteria for light water reactors. Those design requirements specify that each facility limit the release of airborne radioactivity such that no member of the public is exposed to more than 5 millirem per year.

Importantly, actual 1988 release data, regularly filed with the NRC, from the three Southern System nuclear facilities indicate that actual doses are far below these EPA and NRC criteria. These records show actual doses per unit ranging from 0.1 millirem to 0.7 millirem with associated lifetime risks of

1-in-100,000,000 to 7-in-100,000,000. Even taking into account the potential changes in risk factors currently being evaluated, these data confirm that the current ALARA approach to controlling releases ensures that NRC-licensed facilities are below the 1-in-1,000,000 risk factor that is the goal of the air toxics title of S. 1630. In comparison, a roundtrip intercontinental flight results in exposure of about 5 millirem, a typical x-ray results in exposure of about 39 millirem, and natural background radiation exposure averages about 200 millirem per year.

To date, the NRC has taken the primary responsibility for enforcing regulations of radioactive emissions from nuclear power plants and other NRC licensees. In October 1989, however, EPA issued regulations which would impose a § 112 standard on radionuclide emissions from nuclear power plants and other uranium fuel cycle facilities. The Agency promulgated these regulations in spite of its finding that these emissions already provided an ample margin of safety to public health, tacit recognition of the adequacy of existing NRC regulation of these emissions. The Agency also decided to impose Clean Air Act emission recordkeeping and reporting requirements on uranium fuel cycle facilities for the first time. In response to serious concerns raised by the NRC of duplicative and perhaps conflicting regulation, EPA has decided to reconsider these regulations, and the reconsideration proceeding is currently under way.

In the meantime, both agencies have approached Congress seeking statutory clarification of their respective authority to regulate radioactive emissions from NRC licensees. In a letter to the Senate Environment Committee supporting the inclusion of § 303 in S. 1630, NRC Chairman Kenneth Carr stated that "the current NRC regulatory program provides adequate protection against radionuclide emissions from NRC-regulated facilities with an ample margin of safety" and that "additional regulation of these facilities by EPA under the Clean Air Act will provide no further protection of the public health and safety."

In a separate letter to the Senate Environment Committee, EPA and the Department of Health and Human Services requested that " . . . the pending revisions to the Clean Air Act should contain a provision to eliminate unnecessary and duplicative authority to regulate radionuclide emissions from NRC-licensed facilities." In addition, the same letter states that the Department of Energy " . . . shares our concern over the dual regulations and absolute risk standards and potential impacts on nuclear energy, commercial, and research industries."

In response to industry and agency concerns, the Senate Environment Committee adopted § 303, which eliminates regulation under the Clean Air Act of radionuclide emissions already regulated by the NRC under the AEA by changing the definition of the term "air pollutant" in the Clean Air Act. This section clarifies that radionuclide emissions from NRC-licensed facilities are not considered pollutants for purposes of the Clean Air Act. The Southern Company and the electric utility industry support this approach to eliminate costly, conflicting, and duplicative regulation of NRC licensees under both the AEA and the Clean Air Act.

IX. Conclusion

In first enacting § 112, Congress expressed concern about emissions of a "limited number" of "extremely hazardous or toxic" pollutants, and EPA has exercised its authority accordingly. The Agency to date has found that the trace amounts of these substances emitted by electric utility sources do not warrant regulation under § 112, and the available scientific evidence supports this conclusion.

Title III of S. 1630 would substantially alter EPA's mandate with respect to air toxics and could result in premature and prohibitively costly regulation of the trace amounts of these substances emitted by utility power plants. Section 112 regulation of these sources would prove extremely costly to electric consumers and could have a yet undetermined detrimental impact on fuel markets and supplies in this country, without producing any appreciable public health benefit.

Before utilities are subject to such regulation, Congress should require EPA to complete a thorough study of toxic emissions and health risks, to identify any possible benefits of controls, and to consider the costs, feasibility, and energy supply consequences of such controls. The Agency should impose § 112 standards on utility power plants only if the study demonstrates that utility emissions of listed substances pose a significant risk to public health and EPA determines that control technology is reasonably available.

The **Chairman**. Thank you very much, Dr. Goodman.

Mr. Rosenberg, this residual risk issue has been a very troublesome one, as I understand it. It assumes that a person stands at the plant gate for 70 consecutive years, 24 hours a day and does not have any clothes on, and I think the wind is blowing in his direction, and then—it is one in a million or one in 10,000, is that correct?

Mr. **Rosenberg**. Well, I think you posed the right question thereby pointing out it is a maximum individual risk exposure. It is a tool. It should not be the standard.

The **Chairman**. Is that the standard?

Mr. **Rosenberg**. That is the standard to compare to relative risk. What is the maximum exposed individual.

The reason the administration believes that that should be—

The **Chairman**. Well, wait a minute. Without respect—and I want to get at what it is. Is it standing at the plant gate and is it 70 years? Where did that come from, 70 years?

Mr. **Rosenberg**. Well, there was an effort to discern a case study of what would be the potential risk for the maximum exposed individual as a tool to measure different risks. It is not intended to estimate that somebody will actually live there and never move for 70 years.

The **Chairman**. I am just getting at what it is and not what it is designed to do. Is that right?

Senator **McClure**. Well, would you yield for just one correction? It is not necessarily at the plant gate. It is at the point within the plant with maximum exposure.

Mr. **Rosenberg**. No, it is the fence line actually of a plant. It is what the public would be exposed to and not what the people in the plant are exposed to. That is regulated by the OSHA.

This is an attempt to deal with the ambient problem to the society as a whole outside of the plant gate.

The **Chairman**. And it assumes that the wind is always blowing because obviously the wind might go in the other direction. Is that right?

Mr. **Brenner**. No. Generally there are models used to determine how often somebody is going to be exposed. It is not necessarily assuming that the wind is constantly blowing in their direction, but they are conservative assumptions in terms of looking at what is the maximum amount of time the wind may be blowing that way.

The **Chairman**. But it is out at the fence line and is he not wearing clothes or she? [Laughter.]

Mr. **Brenner**. That may be relevant to some considerations involving radiation or radionucleides, but generally we are talking about things that are inhaled and whether the person is wearing clothes or not does not matter.

The **Chairman**. And it is 70 years constantly, 24 hours a day?

Mr. **Brenner**. To model the case where somebody for their lifetime, which is typically an average of 70 years is exposed to the pollutant, that is right.

Senator **McClure**. But it assumes that person never moves away from that point of maximum exposure at the plant perimeter?

The **Chairman**. He is born at the fence line and never leaves. Does he go to school?

Mr. Brenner. When you look at the census data, there are some situations where people literally spend 35 years, 20 hours a day at—living in one spot, and it is to model that kind of situation, the maximum case where you have somebody who is there.

It is not typical by any means, which is the point you are getting at.

The Chairman. I just want to know how extreme it is. I mean, he is always outside. He does not go inside where he might have air conditioning or any air treatment, is that right?

Mr. Brenner. That is right.

The Chairman. Well, now, why in the world did we get off on that?

It seems to me that you ought to be dealing with real people and real risks. I mean, this is the real world. Why is that?

Mr. Brenner. The point that Administrator Rosenberg was making is that that is a tool for the agency to use for determining what are the risks that we should go after first. That is how we use it.

It was not intended to be used the way it is being used.

The Chairman. But this is a terrible distortion. I am not saying that—I mean, for the purposes at least of this question I am not saying it goes too far. It just distorts what the real risk is to real people.

Mr. Brenner. It is the wrong way to make a determination of whether to control, and we feel that very strongly, and we agree with you that that is not the right way to determine whether you should put additional controls on sources.

It should be looked at in conjunction with a whole bunch of other factors which the Senate bill would not let us do.

Senator McClure. Mr. Chairman, would you yield on that point because I like your answer. I just wish you applied that in practice because you are threatening to close down a plant in the state of Idaho on precisely that basis. Not under this bill, but under current law.

And you are threatening to close the plant down on precisely that basis, 1 in 10,000.

Mr. Rosenberg. That is why we are seeking the change in current law. The current law requires us—does not allow us to consider what the President said we should consider in this bill.

MACT is a different standard than current law. Current law does require us only to consider health consequences. It has led to litigation, and it has not led to reasonable regulation that would protect the public health.

And so, one of the reasons there is an amendment proposed in the form of MACT instead of current law is that current law does not allow us to consider things other than health standards, and there has been a lot of litigation that led the administrator to decide that under the current law we had to apply a 1 in 10,000 although we are not even applying under current law the absolute bright line proposed in the Senate bill.

The Chairman. Now, would you, Mr. Rosenberg—now, Mr. Goodman talked about this remote location and no threat to health, and it was going to shut down a lot of oil wells, and I have heard a figure—I forget how many hundred thousand barrels a day—but a very significant amount.

Is it true that S. 1630 would shut down a lot of oil wells with the present bill, which the President's bill would not, and do you know how many? Is that true and why?

Mr. ROSENBERG. We estimated that there would be more curtailments. We do not have precise information.

The CHAIRMAN. Do you have that, Ms. Stuntz?

Ms. STUNTZ. We have tried to make some estimates of that, but it is difficult since we do not know exactly what the MACT standard will be that would be applied. But, clearly, we think that there will be more disruption under the Senate bill because there are going to be more of these small facilities covered. Under the Senate bill they would be required to apply MACT to facilities emitting ten pounds or more, and that does not take very much. That can be four or five wells and a couple of gathering tanks and you are there.

Senator FORD. Mr. Morrison, do you have some kind of figure on the wells?

Mr. MORRISON. Yes. I had some numbers and my associate tells me he thinks that the basis of these numbers are studied by the API was it or Mid-Continental Oil and Gas Association, and the numbers were that it would close 29,000 wells. These would be marginal wells that could not afford this cost, and that would amount to about 140,000 barrels a day of production and 500 million barrels of oil reserves in the ground that will not be drawn out.

Senator FORD. That is nationally now?

Mr. MORRISON. I assume so.

The CHAIRMAN. Does that sound correct to you, Ms. Stuntz?

Ms. STUNTZ. Well, it might be a pessimistic approach, but I do not think it is inconceivable. Again, it depends on how much flexibility the EPA will be given in the designation and application of MACT. And as much as I respect Mr. Doniger, I have to tell you as a representative of the NRDC's favorite defendant that we do not see very much interest in looking at cost when we are talking about our facilities, and we do not see very much interest in looking at risk.

I think that companies will be put at risk and small producers will be put at risk if they do not apply the best or maximum available control technologies even to existing facilities. There is at least the risk of litigation and uncertainty and your small producers are not going to be able to handle that.

The CHAIRMAN. By the way, you do have an answer here that points out that in 1988 there were 612,000 producing wells, of which 454,000 or 74 percent were stripper wells. And they produced 442 million barrels of oil.

Well, it seems to me that a stripper well, by its very nature, is producing so little oil that you cannot spend a lot of money on. I mean we have an oil field up in north Caddo Parish—County, to you—where these wells are held together with baling wire, but they produce a lot of oil.

You know, some of them produce one and two barrels a day, and the trick is to keep them going with a minimum of money, but they keep them going and they produce a lot of oil, and that is important for us to do.

Now I may be dead wrong, but I do not see really a health risk to these things. I mean they are way out there where it is all diluted. The President's bill would not prevent that, is that right?

Ms. STUNTZ. The President's bill provides flexibility to the EPA to make an assessment of these area sources, these very small sources, and to apply a reasonable standard. The EPA can consider what the risk is and what can be done to minimize the risk in a way that is also cognizant of other considerations like energy production.

The CHAIRMAN. And your guess is that, under S. 1630, you would not have that kind of latitude to reasonably define the risk?

Ms. STUNTZ. All categories must be controlled. I said there was 10 pounds—it is not even 10 pounds. There is no de minimis exemption whatsoever.

The CHAIRMAN. Well, that seems to be a very strong case. Obviously, I have got some more questions.

Senator Heflin has been trying to ask questions for the morning and afternoon yesterday and was not able to do so, so Senator Heflin, let us recognize you at this time.

Senator HEFLIN. Well, let me first ask questions to Dr. Goodman.

Assuming the most stringent interpretation of this Title III for controlling hazardous air pollutants, why are the utilities implicated?

Mr. GOODMAN. The utility industry burns significant amounts of coal, and many of the items on the list of concern in all the bills show up in trace quantities.

There are these arbitrary numbers that, if you exceed 10 tons a year and accumulate to 25 over several components, potentially in the future or now—we do not always have very good databases on exactly what trace quantities are in our goals—we potentially could exceed those numbers.

If you look at a 1,000 megawatt powerplant nominally running at a 60 percent capacity factor, we use well over two million tons of coal a year in that unit. So to exceed something like 10 tons, the potential is there. And it is more than just chlorides.

The way this bill is written, and the way these analyses would be done quickly in various source categories, we feel very strongly that with BACT or MACT maximum technology, EPA is going to have very little flexibility and therefore they are going to conclude that something similar to flue gas desulfurization and the use of bag houses on all those facilities will be necessary.

And we just do not think they are going to be—we think that is a big risk.

I would like to make one other comment. It was pointed out to me in my testimony earlier, I did mix up the premium of whether it was on low-sulfur coal or high-sulfur coal. I want to make sure that it is stated correctly. We pay a premium, normally, for low-sulfur coal, and it is in those cases we do not use flue gas desulfurization equipment.

Normally, high-sulfur coal is cheaper, and if you had something like flue gas desulfurization equipment, it will be the fuel of choice.

Senator HEFLIN. Now on this implication of the utility industry, do you have an abundance of data on these substances from each plant?

Mr. GOODMAN. No, we do not.

EPA has several studies underway to better characterize coals in general. The Electric Power Research Institute is doing that. Sometimes the test procedures just to find these very small quantities in the fuel are not in place, so there is generally a pretty poor database on many of the substances that are listed.

Senator HEFLIN. Are all coal-fired units implicated? And is it coal-specific, depending on low- and high-sulfur coal? You may have touched on that, but are all the coal-fired units implicated in regards to this Title III?

Mr. GOODMAN. I think initially they would have to look at all coal-fired units. There has been a lot of discussion of chlorides, which, in general, the discussion has been that is more prone to be a western low-sulfur coal problem. I am not sure that is true.

But I think initially you are going to have to look at all of them. That is one of the reasons we say that it is risk assessment done properly under a three-year study, and then ongoing, probably is the way to go. They are all going to fall under it, depending on what substance we talk about.

Senator HEFLIN. Other than chlorides, what others do you consider to be potential types of chemicals or materials that would come within the Title III hazardous air pollutants?

Mr. GOODMAN. Well, there is a list, I think, of nearly 190 in the way the bill is written. And then the discretion or the ability for EPA to add additional substances.

If you look at the periodic chart and then you look at what can be in the mineral content of coal, I am not sure I can answer all the ones one might consider. There are going to be very small trace quantities.

They currently have been looking at various particulates, cadmium being one of them, radionuclides have been looked at, and things more related to the particulate side. And then there are the volatiles like chlorides. And there has been a lot of concern recently about mercury.

And those are the kinds of elements that we would expect to be talked about.

Senator HEFLIN. Assuming the most stringent interpretation of this Title III, what would be your company's specific compliance response?

Mr. GOODMAN. Compliance response is similar to those house figures that I have given out, that we would feel we would have to look into: retrofitting, bag houses, and putting scrubbers on each of our units. Which would be over a $12 billion capital investment.

Senator HEFLIN. Does not that strategy make other provisions of the bill moot, like calling for scrubbers for toxics but not for the sulfur-dioxides resulting in a 100 percent nationwide scrubbing?

Mr. GOODMAN. That is right. I think it has been said several times that the air toxics provision makes the acid rain provisions irrelevant.

Senator HEFLIN. On the maximum available technology, the MACT, is there a date on that? I mean can it change? Can you take action?

And we will say that you determined that coal has mercury and you are going to take action to try to comply with it. And then, say you take the action and you get it in place three years. After you have got it in place, and then another maximum available technology comes along, under this bill, would you be forced then to comply with that?

Mr. GOODMAN. Although I think some flexibility is implied, I think you are correct that things could keep continuing to be ratcheted down on you. It implies that maximum available control technology is 90 percent removal or better.

And in several cases we do not know enough about removing these things from flue gas that it might be a step-type of activity.

It was mentioned earlier I think by the EPA testimony that this issue of treating chlorides separately, so you have got three years, then they try to do something, you could have things being phased in at you at all sorts of schedules.

The three-year study provision we think would give it much more of an organized structure to answer the questions, and if we had to do something, phase them in with the acid rain provisions.

Senator HEFLIN. We are, of course, at this committee looking at the issue of an energy policy and how this proposed legislation will affect energy policy on a somewhat long-range basis.

We went through a situation where, from about 1976 to 1980, we had a great emphasis on an energy policy designed to look at alternate sources of energy. Then following 1980, there was pretty well a shutdown in regards to government policy which would encourage looking at alternate sources of energy. And very little research occurred on an overall basis. Some, however, has occurred over the last eight years.

Now on an acid rain basis, where there is a no-growth policy, will such a policy under the acid rain deter or discourage the research that could go on not only on alternate sources, but could it also discourage and deter pertaining to things under acid rain?

Now I mention acid rain.

Then, looking at the other side, in regards to the Title III, it seems you might well have an encouragement for all types of research and developments of technology to go on basically on the idea that you have got a market that has got to buy you.

Are those two policies inconsistent as it would apply to a policy of research, as it would apply to acid rain, and then to the Title III?

Mr. GOODMAN. I think we have a policy of research that our company is very much involved in, related to the clean coal technologies. We have four Phase II clean coal technology projects that fit in that category of retrofits and how do you treat the existing fleet of units if you need to do something with them.

We think that those projects all will result in significant cost savings if we have to apply them. The way these bills are written and the time frames of compliance under the acid rain provisions, we may not have the opportunity to really take advantage of those results.

When talking about Title III, I think it, taken to this extreme interpretation, has a real damaging effect to our energy policy.

If our long-term energy policy is based on coal as our largest national resource—we are also committed in our company to nuclear and hydro, and if gas is available at a proper price we are going to use that, too—but under the air toxics provisions you are going to make the use of coal far more expensive.

And what our future decisions will be on how to use coal is going to be difficult. Because we are talking—I was interested in Mr. Rosenberg's comments yesterday about a 3 percent rate increase under the acid rain provisions.

Well, when averaged over a period of years, he said it correctly, but our peak year rate increases are more like 8 percent for the acid rain provisions, 25 percent if we take the full blown air toxics provisions added on to it. We are not sure our customers are going to be able to buy the product.

There was the discussion yesterday of the nuclear business, and with our nuclear fuels capability and that price increase, what would that do to us in international markets?

I think our customers and lots of other areas of business have exactly the same problem. They do not think 8 percent or 3 percent or 25 percent or easy things to take.

And coal is the basis for those costs going up. So we are going to have to reassess what our implementation of the energy policy in our company is going to be if we get all these provisions.

I think the other side was the discussions made of health impacts or impacts on the economy.

Unemployment is a health impact. We live in a part of the country where we do not have a great reputation for education. We have poor health quality for children, especially in rural areas, high death rates for premature births, death rates of children, and all of those issues are health issues, too.

And when you are talking about, for our acid rain provisions, taking $1 billion a year out of the southeast annually for it, or $3 billion for the air toxics provisions, those have real health implications, too, as well as economic.

Senator **Heflin**. Mr. Rosenberg, let me ask you about some enforcement provisions. It seems that there are almost triple enforcement hits that could be excessive. The bill requires sources to pay an excess emissions fee of $1,000 per ton and requires them to offset the excedent with the succeeding year reduction. The offset requirement would be indefinite, and it makes each ton a separate violation in regard to this.

Is this triple enforcement hit necessary?

Mr. **Rosenberg**. The goal on the $2,000 per ton is to have that be self-enforcing because we really do believe that the industry can achieve the results in a range under $1,000 per ton. We have allowed for the trading system to work in such a way that if you failed to do that you can acquire additional allowances as well either from your own plants or from other people.

So we have established what we hope would be a self-enforcing mechanism that gets EPA out of the hair of the industry by essentially saying to the industry here is the target.

We will jointly establish a monitoring system on each smokestack so that the actual number of tons will be monitored on a daily basis by the industry so they know where they are going. This is an annual target, so they will know on a daily basis what is going on, and if they are getting close they have time to take action.

So we would hope that there would be a minimal amount or a minimal number of situations where at the end of the year a company exceeded their requirements.

The enforcement provisions I think beyond that really would go to bad faith rather than simply guessing wrong. If they guess wrong and they want to buy the permits from EPA, the statute essentially says we will sell them to you for $2,000 per ton if you make it up next year.

The other enforcement provisions really would relate to not simply guessing wrong but acting in bad faith and not attempting to seriously meet the requirements by failing to—I mean, it is one situation if a scrubber does not work that has been installed, and it is another if a firm chooses not to put one in thinking that it would be needed.

Senator HEFLIN. Mr. Chairman, I have a number of other questions, but I do have to go to another matter which is very important which I have to attend. So I will submit those in writing.

The CHAIRMAN. Thank you, Senator Heflin.

Senator McClure.

Senator McCLURE. Thank you very much, Mr. Chairman.

I want to return for a moment to find out what the administration believes MACT means as compared to BACT. Now if I understood Mr. Doniger, he was saying in effect that BACT applied plant by plant and keeps you on a constantly escalating plane of requirement, and MACT fixes the requirements at points that have been adjusted. If I recall, and I hope I am quoting him correctly, he was in effect saying that MACT was a lesser standard except at the period when it is adjusted upward to the BACT standard.

Mr. ROSENBERG. I would not say that. I think the standards would be comparable in the sense that we would consider technology capabilities, costs and what is being done at other facilities which are demonstrating the technology.

The difference is that BACT is a determination made on each application for a new facility. This will be an attempt to aggregate for existing facilities, all refineries as an example. It might be one source category, and it would not be finetuned to a particular refinery in a particular place.

Since BACT is applied on a case-by-case basis, we wanted to use a different name but the concept of how we would go about designing a standard for a broad group of plants, a source category, would be similar in the sense that we would consider costs as well as health and technology risks.

Senator McCLURE. May I then rephrase it? I want to make certain that I understand what you are saying.

The BACT is a specific standard for a specific plant, and MACT is an average standard for an average plant?

Mr. ROSENBERG. Well, it will be a standard for an average plant. It might not be an average standard. It is still the maximum achievable control technology.

Senator MCCLURE. It would be the BACT for a class?

Mr. ROSENBERG. That is correct. That is probably a better way to say it.

Senator MCCLURE. The same thing as BACT, except you do not adjust it for an individual plant. You make it for categories?

Mr. ROSENBERG. That is right, for a class. That is a better way to say it.

Senator MCCLURE. Madame Secretary, do you agree with that?

Ms. STUNTZ. EPA will be administering it. I generally do agree with that. I think there may be one other significant difference. They are the experts, I am not; but my understanding is that BACT is applied to new facilities as part of a new source review as they come up. MACT would be applied to categories of new but also existing facilities. In other words, the standard for existing facilities could also change every 5 years.

Senator MCCLURE. It is the same standard, only it applies to a different group, that is all, not a different standard.

If I envision it correctly, and I do not know if you can see it here, BACT is a constantly escalating line. MACT, being fixed for a period of time, looks at the BACT for that group and fixes that for a period of time and then adjusts it at the end of that period of time back to where the BACT would for an individual plant, if indeed that is the standard for that group.

So MACT stairsteps up the same line that BACT takes on a more incremental approach plant by plant.

Mr. ROSENBERG. There is another point here. The administration bill does not require the 5-year adjustment. The Senate bill does.

Again, I think it is important to put this in context. The reason the administration proposed this concept is that we are failing to regulate properly under the current section 112. We think we have an enormous amount of work to do in the next 7 to 10 years to get the 80 percent reduction in risk and do all of these analyses and these estimates.

The debate is what is going to happen in Phase II after we do a very good job on Phase I. I think that since we are talking about what is going to happen in the next century with a lot of new technologies, it would be better policy to give the administrator some discretion on figuring out how that works within the context of the economy 10 years from now than to today write a rule that could require the steel industry or the tire industry or the petroleum industry or the chemical industry potentially to close down ten years from now after we have achieved the 80 percent reduction.

Senator MCCLURE. That is a little different question, but I understand what you are saying. I am just trying to get through my head why we use different terminology to achieve the same end.

If I understand what you are saying, in part it is an administrative convenience to set a standard for a group rather than having to make a review on each individual application; but since you are making a standard for a group which is at the maximum achievable, which is the same at BACT as applied to an individual plant, you then do not have to make the reviews on the individual plant. You just say this was for the group, apply it to your plant?

Mr. **Rosenberg**. That is correct.

Senator **McClure**. I need to understand that, because I do not want anybody coming back here later and saying maximum achievable is a quantum leap, more strict than BACT is today with respect to an individual plant.

My understanding from both you and Mr. Doniger is that that is not the intent of this language, and we will attempt somewhere in legislative history in addition to what is said here today to define that so that everybody understands not just now but 2 years from now or 5 years from now or 10 years from now what Congress had in its mind and what the administration had in its mind when this new terminology was used.

The courts looking at that are going to say, hey, you must have meant something, and they sometimes—not often but sometimes—look at congressional intent in order to try to determine what the bill means and what the law is, in effect.

Now section 112(d)(1) lists a number of possible controls which must be considered in setting MACT standards including process changes and substitution of materials.

Do you interpret this language as giving you the authority to force utility boilers to switch fuels such as from coal to gas?

Mr. **Rosenberg**. No. I think on the utility side what we would prefer is a study for three years to determine the appropriate thing to do, then make decisions under the regulatory authorities of EPA to regulate those considering and coordinating what is being done under the acid rain title. I would not think we would ever get into the question of what should be the appropriate fuel. We probably would have a standard for oil plants and a standard for coal plants and maybe a standard for gas plants.

Senator **McClure**. Madame Secretary.

Ms. **Stuntz**. If I understand your question, which was under the Senate bill could you theoretically do that, I certainly think that is contemplated. It says reduce the volume of such pollutants through process changes, substitution of materials or other modifications.

Senator **McClure**. You would read the Senate bill as saying that the administration could force fuel changing?

Ms. **Stuntz**. Yes, I would.

Mr. **Rosenberg**. I think what EPA would most likely do is establish a performance standard that would allow those items to be those things that somebody used to meet those performance standards. It is unlikely that even under the Senate bill that we would go into the realm of mandating particular fuel.

Senator **Ford**. The fuel would be a free choice?

Mr. **Rosenberg**. I cannot imagine even under that stricter standard that we would get into that.

Senator **McClure**. Let me say this based upon more experience around this town than you have had. Somebody is going to try to force you to do that whether you intend to or not if indeed you have the authority.

As I see what is said in the bill plainly, and I read it as does Secretary Stuntz, you have the authority, and somebody is surely going to ask you to use that authority or question why you have not, regardless of your intention.

Mr. ROSENBERG. There is no doubt that the Senate version of the air toxics bill is a can of worms in a lot of areas, and we would strongly request that whichever Senators wish to join us to return to the administration proposal which itself is a strong piece of legislation and was introduced last year almost in its entire form by Representative Dingell on the House side—this is a very strong piece of legislation and will make a lot of progress, but it does not make sense, it seems to us, to take all discretion from the administrator as we go forward for 10 or 15 years in areas in which we do not have data.

I want to make one point about the risk assessment. We think that it is a useful tool but do not think that it is as precise as it appears.

Senator MCCLURE. Let me put it this way. I believe, as do most people, that risk assessment is a good tool to rank comparative risks so you can concentrate on those with greatest risk. When you use a risk assessment as an absolute standard which must be met, however, then you are using it for things for which it was ill designed and simply cannot adequately defend the precise application.

I would again say that is precisely what EPA is doing on the radionucleides issue, so do not tell me it is not possible that it will have that effect. It is having that effect under your department or agency right now.

So I am concerned about it, and I am glad you are concerned about it. I hope we will be able to resolve some of the other questions under existing law and application today, because I agree with what you are saying. I just wish your employees agreed with what you are saying.

In the case of the control of toxic emissions after controls are installed, if the risk assessment showed that there was a risk greater than 1 in 1 million to exposed individuals, what further actions beyond MACT would be required of power plants?

Mr. ROSENBERG. Well, if in fact the more extreme results did not reduce the risk to the bright line, I guess they would have to close it. I do not think that is likely.

Senator MCCLURE. Mr. Doniger indicated they could get a 5-year extension, and if at the end of the 5 years you still cannot meet it you could get another 5-year extension.

Mr. ROSENBERG. That is only if you achieve the ten to the minus four. What he failed to say was that if you fail to achieve the ten to the minus four for any reason, there is no exception.

Senator MCCLURE. Then you would close?

Mr. ROSENBERG. I think in the utility area that is extremely unlikely, but in some of the other areas it is not. In the steel industry, in some of the older industrial sectors it is very, very difficult to imagine that every major plant would achieve ten to the minus four even if they spent hundreds of millions of dollars.

I mentioned yesterday that I was at a major steel plant outside of Detroit with 5,000 employees that had spent $1 billion and had a budget for improving their coke production of several hundred million, and neither the EPA people nor the State people nor they felt that even if they spent that money there was any assurance that they would meet a bright line standard even though they were modernizing their mill in a very aggressive way.

If there were a bright line standard, it may very well be that the billions of dollars that might be required was not justifiable and they would have to shut down, whereas we would prefer a standard that get us the 80 or 90 percent improvement and then establishes schedules to go beyond that without mandating an uneconomic result for a very small level of risk.

Senator **McClure**. Coal contains trace amounts of chlorine, fluorine and other Table A substances which might trigger the 10 to 25 ton violation threshold for coal-fired boilers if the chlorine study provision, which is in section 112(e)(5) was correct, why not a similar study provision for other pollutants at least until we can quantify the cumulative impacts of acid rain and any additional ozone-related NOx controls before we impose new air toxic controls.

Mr. **Rosenberg**. Well, that is what is in the Administration bill, is a study of all of the health risks, a deferral of utility action, until that study is complete, which would give the EPA the opportunity to coordinate between the different sections of the bill and so we do not have—even if we impose additional obligations it would be ridiculous to do it in seriatum. We should do it all at once, so that the companies can plan it efficiently.

Ms. **Stuntz**. The only thing I would say, Senator, is I am not sure I agree with your question of calling what is in the Senate bill a study on chlorine. It appears to us that that section says, EPA shall not promulgate a standard on chlorine for 3 years, and then it will be free to do so after that. It does not really call for a study, as I read it.

Senator **McClure**. But you would support a study?

Ms. **Stuntz**. Absolutely.

Senator **McClure**. You would prefer that the study be mandated, as well as conditioning the authority? You could not impose standards without the study.

Ms. **Stuntz**. We prefer the Administration's bill.

Mr. **Rosenberg**. I might point out, senator, that the Administration bill does not simply say "a study." It says a 3 year study where we assess the health risk, and then we would be obligated under the Administration's bill to take regulatory actions to deal with risks that are deemed by the Administrator to be unacceptable.

Senator **McClure**. I want to just read into the record an answer which was given by DOE in response to submitted questions with respect to the impact of the standards, the toxics provisions on oil production, and DOE did not, by their answer, indicate other than to repeat information that was given to them by IPAA and API.

IPAA estimates that under both S. 1490 and S.1630 125,000 stripper wells would close and that over 4,000 new wells would not be drilled. API estimates that 175,000 stripper wells, each producing two barrels or less per day, would close. IPAA also estimates that 29,000 of the wells would be permanently plugged.

Now, that is in the DOE testimony, but again, DOE is not confirming the accuracy of the figures, simply providing to the Committee the figures which have been produced by those two organizations.

But it does give you some idea of the magnitude of the problem in a country that cannot yet find a way to get a favorable balance of trade. That is one of our economic problems in this country.

A country—and I am not going to make a long speech here, Mr. Chairman, because most of you have heard it before—but a country cannot do well that continues to consume more than it produces, whether it is a domestic deficit, and the domestic budget of this country, or individual personal debt that escalates more rapidly than personal income, or a balance of payments.

This country, and the people in this country, are consuming more than we produce, and that is a formula for disaster if it is continued over a very long period of time, and I am very much concerned that we do not, as we look at these issues, relate an environmental issue to the other economic and social issues which we have.

I will repeat again what I have said many times before, one of the best statements on energy came from the NAACP, and they said several years ago they support a national energy policy of having enough energy because they knew that they could not in this society gain all the benefits of our society if they have to take something away from somebody else.

They will achieve equality in our society only as the economy grows enough to provide benefits to them as other people in our society enjoy benefits, and so failure to have an adequate energy policy in our country condemns an underclass to permanent underclass status.

Now, put that into a national policy equation and balance that against other environmental and social concerns. Do not ask us to do it in the vacuum of saying the environment is all there is. Close down a 5,000 employee plant, and find out what happens to the health effects, to the families, where the wage earner is unemployed. Talk about your suicide rates, talk about heart disease and stress-related illnesses. Those are all a part of the health equation too.

I am very much concerned that this bill as formulated by the Environment and Public Works Committee—and they are fine gentlemen. I understand they have asserted it as well. But I do not believe that the bill that they have produced has anything like the reasonable balance which our society should require.

It is a tragedy that we are at this point. I hope we will not rush to a judgment on that bill before we have had an opportunity to digest what it means to our society in terms of competitiveness, in terms of social policy, in terms of rural policy, in terms of energy policy, as well as in terms of environmental policy, and I am afraid that what they have done is get very myopic and look at only one very small part of the larger concerns this country must meet.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator McClure. Before I call on Senator Ford, let me just ask, we had written questions for October and November alternative fuels hearings. EPA sent us responses to the October hearings, but still owes us for November, and DOE has not responded yet to either set. I hope we will get those in time to do some good on the floor, so I would urge you to do that.

I also would say, if any members of the Committee want questions for the record they should get those in by noon tomorrow, and with that—and I want to thank every member of the Committee. Senator Ford, thank you.

Senator FORD. Thank you, Mr. Chairman. I will not take very long. I have been listening, and some of my questions have been answered.

Let me ask Dr. Goodman this question. When the so-called Clean Air legislation has passed the Congress and the President has signed it, can you at that time, with what you know now—and I am not fixing you and I do not want you to be in concrete on it, but give me a judgment—at that time, can you reasonably say whether you are going to scrubbers or you will be able to mix, cofire—do you think you can make a judgment for the Southern Company at that time?

Mr. GOODMAN. I think, in terms of answering your question, for what we know today in analyzing something like the Administration bill, we have a strategy, or an implementation strategy that probably will be close to what we will ultimately do.

It is a balance—by the year 2000 it is really a balance of about half flue gas desulfurization, 12,000 megawatts of control and the balance being done, about half of our costs related to switching to low-sulfur coal.

Senator FORD. I am not really wanting to get into that, but what I wanted to know is, at that time when the bill is signed into law, you could make a judgment on basically on what your strategy will be?

Mr. GOODMAN. Yes.

Senator FORD. Now, under this legislation let us say that your most pessimistic attitude earlier was that under Title III and so forth you just have to go ahead and scrub everything. Now, you said that you would have to scrub that—let us take that worst scenario, I guess.

Who would you order your scrubbers from, and where would you get them?

Mr. GOODMAN. I think first, under the worst scenario, we would have to decide really who is going to buy our product. I mean, we do our scenarios from compliance by assuming a business as usual, or what will the world look like in the late 1990s, and that scenario is so extreme I think we are going to have to redecide, would we buy it? With that discussion——

Senator FORD. Say you decided to buy the scrubbers, who would you buy them from and where would you go to get them?

Mr. GOODMAN. At the moment, we are the contractor to DOE on a major flue gas desulfurization clean coal project, a system that is a sparger-type scrubber system, forced oxidation limestone system.

We, through the 1970s—late 1970s and the 1980s have done basic research on scrubbers. We have had five 20-megawatt demonstration plants in the late 1970s. A decision we are going to have to make is, do we do that through vendors or do we do—basically be our own engineer for those scrubbers, which we are capable of doing. The question is, will that be the most cost-effective?

If we went the bid approach, we think there are several competitive companies out there who could compete.

Senator FORD. In the United States?

Mr. GOODMAN. In the U.S., although many of them, including ourselves, have technologies that are foreign-based, because this country basically has not been involved with many—you know, the suppliers historically have not developed their own technology.

Senator FORD. Would I be correct in saying that there is only a couple of companies that would be looking to that that you could really go to with some confidence and the rest of them would be foreign sources?

Mr. GOODMAN. That is true. The foreign sources are supplying the technology. They will have a U.S. representative and maybe a name that you would consider U.S.

Senator FORD. But it would all be over there, so for all practical purposes we force all the utilities and so forth to go to scrubbers and then we are shipping jobs overseas.

Now, Dr. Goodman, you talked about your association with DOE, and I guess it is a new technology that you are working on, and you said I think, earlier in your opening testimony, that there are several there that if you could use them would be more cost-effective than the scrubbers.

What I took you were about is these new technologies burn coal more cleanly. These technologies would be more cost-effective. Under the date of the year 2000 with a contract at that time and the extension of three years to complete that, how many of these technologies would have the character to give your Southern Company the confidence to purchase them and install them, retrofit, repower or whatever it might be? How many do you think will be completed by the year 2000?

Mr. GOODMAN. Let me finish the last question and then answer that. I think in terms of the money spent on scrubbers, although foreign technology is there, there would be a lot of jobs in terms of construction in this country. I mean, the technology is licensed in many cases.

When asked what technologies will be available by the year 2000, most of the technologies we are working on as a company are really retrofitable technologies. The reports that will be generated by us and DOE on those technologies will come out prior to 1995—1994, 1993.

The question will be, being able to buy it and how long it takes to get into the process so you can implement it and buy it, and a good example of that is on our scrubber project. One of the cost reductions of that advanced scrubber is to build the system from fiberglass. The fiberglass suppliers that we are using——

Senator FORD. Now, is that in the pilot stage?

Mr. GOODMAN. It is in the demonstration stage. It will be 100 megawatt demonstration, and it will be a large vessel spun from fiberglass. Historically, vessels of similar size but in a different way, different life requirements, have been used in the petrochemical industry.

If we decide to do that in a major way, U.S. industry is going to have to gear up to be able to do it. It is not like there are lots of suppliers.

Senator **Ford**. How long would it take them to gear up? If you decide it has the characteristics to give you the confidence to move on then, how long will it take the American industry to gear up to put that technology into place?

Mr. **Goodman**. This is one of those discussions of your projecting what others will do, but we feel, to make real market penetration and to be able to get people to learn what we have learned in these demonstration projects, that potentially, since you have to make your decision prior to the year 2000 even if it is going to be available in 2003 or 2005, that we think five or ten years.

Senator **Ford**. Well, you cannot do that under the legislation, as I understand it.

Mr. **Goodman**. That is correct, and that is why I think Mr. Yamagata was giving good examples of how much time might really be needed, and I think five to ten years of being able to gear that capability up and implement it past the period by which we finish these studies in many cases would be reasonable.

Senator **Ford**. What I am concerned about—and I do not want to get into past history—but in 1972, I started on clean coal technologies. My state has put in in excess of $60 million of their money into research and development. We have two projects now. DOE is working with us very closely at one generating facility in far west Kentucky. We have one in demonstration stage. They claim now it is going 105 percent. And I do not know what 105 percent is, but I like that sound anyhow. And now we have started a pilot project.

And so, it appears to me that there are a lot of things going on out there. But in 1998, if I get the information from DOE that there will only be one on the board that would be useable in 1998, the others are going to be a very close fit in the year 2000, maybe one, two, even three.

Now, I do not want to close these technologies out, because under the administration's bill as I understand it, and I could stand corrected, is that you sign up in the year 2000. You are given 3 years then to construct it, and so you have a forgiveness period of three years.

But if you do not have something in the year 2000 that you feel confidence in and you can spend that kind of money on, you just cannot move. And so you go back to whatever you have the confidence in. And the new technology may be so much better. And you have that kind of feeling too, or you would not be in the experimental business and research business with DOE.

And so I want to leave it right there. But I think you understand where I am coming from, and I understand where you are coming from.

Now, I want to compliment, Madam Secretary, for your stamina. You have been here, and I want you to know that I appreciate it. And I appreciate your answers. So, therefore, I am going to pass you.

Mr. Rosenberg, will 3 years be enough for the study as it relates to the toxics?

Mr. **Rosenberg**. We think it will be, sir.

Senator **Ford**. Would 5 years be better?

Mr. **Rosenberg**. We would not need more than 3 years.

Senator **Ford**. You are sure of that now?

Mr. **Rosenberg**. Yes, sir.

Senator **Ford**. All right. I just want to be sure that we do not look at that.

Now, this has been bothering me. There is a deadline on acid rain in this bill, 1995 and the year 2000, period. But in every other section there is dates from the date of signing of the bill. There are all kinds of leeways. And so, time is running, Mr. Secretary, time is running, and acid rain is getting the crunch. Why cannot we say to that portion, the acid rain portion of this legislation, upon signature of the President or date of enactment?

I do not know whether you were around when we went into surface mining problems, or whether you have looked at it very hard, but date certain or time certain, we have never been able to straighten it out, because they rush real hard to meet it, and they could not meet. And then they are all in trouble, and we become the favorite defendant, Madam Secretary.

So, this time crunch and setting a hard date out there, when you are not setting a hard date for others, seems to me somewhat unfair.

Mr. **Rosenberg**. Two points on that, Senator.

First of all, the dates that the administration set were December 31, 1995. The dates in the Senate bill are January 1. And so it is effectively, although they are both 1995, there is really——

Senator **Ford**. I am not worried about—I am worried about both of them. I am not trying to compare—look, yours is so much better, everybody is running to the administration's bill for cover. And you are beginning to get some help that way, because compared to what——

But why not? You see, these dates have not changed in 3 years. They have been the same. Everything else is on date of enactment, but poor old coal and acid rain and utilities are still in the crunch.

Mr. **Rosenberg**. Well, if the Senate and the House and the Congress do not present a bill to the President by, say, the middle of the year, sometime this summer, I think that you have a good point.

Senator **Ford**. I think I have got a good point anyhow.

Mr. **Rosenberg**. When we analyzed the dates, we thought that sometime in 1990 the bill would be passed. But if it gets beyond that, I think it would be very difficult not to move the deadlines.

Senator **Ford**. I agree with that. But I am very, very concerned after spending—I can hear Senator Jennings Randolph talk about flying from Charleston, West Virginia back in 1944 to Washington, D.C. in an airplane that used oil made from coal, and we still cannot get anything done. You know, I have heard that.

Well, I am kind of in clean coal technologies that way since 1972. I have got a lot of sweat and blood and tears in clean coal technology, because it is the only way to give my state, in my opinion, some economic stability.

And I would hate for a couple of years to eliminate them from that possibility.

Now, I do not know how we can get to it, and I think Linda could give us some judgment on it, or we can get some judgment, when you all get your heads together, when these technologies will have that character that will lend confidence to those who want to comply with this piece of legislation, as it relates to the clean coal technologies.

So, I want you to—6 months is 6 months. If it is 2000, July 1 in the year 2000, we might get the other one on board. It is that close. It is a real crunch. And I am not sure you can push the research any harder than it is being pushed right now. I compliment the Department. They are working hard. And we have got two more groups to be awarded. Have we not? Is not that correct?

Ms. **Stuntz**. One more now, I believe. We have just announced four.

Senator **Ford**. But you have one next year and the year after that to be awarded.

Ms. **Stuntz**. That is correct.

Senator **Ford**. And it takes money, and it takes applications, and it takes decisions to make if this one it going to be worth putting taxpayers, dollars in. So, I am not begging. I am going to start fighting, because I want it delayed sufficient that we can have confidence that when this bill triggers in out there that this technology will be available. And I am not sure a 24-month slide would hurt you too much on the far end, and maybe not up front in 1995.

But a slide would not hurt at the far end in my opinion. And it might give us a chance on these technologies.

I see there is no other questions by my colleagues here, and I will adjourn this meeting.

[Whereupon, at 12:25 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Pre-Hearing Questions

U. S. DEPARTMENT OF ENERGY
Responses to Questions
from
Senator Johnston
Committee on Energy and Natural Resources
UNITED STATES SENATE
JANUARY 24, 1990

QUESTIONS FROM SENATOR JOHNSTON

Question 1: What is the effect on the emission trading system of the fact that buyers and sellers of emission allowances would be regulated firms rather than profit-maximizing, unregulated firms? What is the effect on the trading system of the fact that there is risk of future emission regulation changes?

Answer: Profit-maximizing firms, whether regulated or not regulated, have an incentive to participate in the emission trading system because they can increase revenues and profits or lower costs through participation. Regulation, however, could prevent the trading system from operating in the optimal way.

Some state regulators have claimed that they will not permit allowances to be traded outside their states. Some utility executives have claimed that they would not sell excess allowances for fear of being judged "imprudent" by state regulators, should subsequent growth require a utility that sold allowances to purchase them, perhaps at a higher price. Some utility executives also have claimed that the risks of allowance trading to them far outweigh the potential benefits, especially if these benefits are passed through entirely to ratepayers.

While we are aware of these regulatory-related issues, we do not believe they will prevent the development and

Answer 1
(Continued)

operation of a workably competitive emission trading system.

There are several reasons why regulation should not unduly inhibit the trading system. First, and primarily, it is in the interests of the consumers whose welfare is the ultimate concern of state regulatory authorities to support the trading system. As the recently passed Ohio Public Utilities Commission Resolution stated:

> RESOLVED, that it shall not be the policy of the Commission to encourage utilities to hoard the permits earned, but rather to best utilize them to reduce the overall costs of complying with clean air requirements and to assure that Ohioans maximize the economic benefits from permits during the limited time window in which the permits will be tradable and of economic benefit.

This only makes sense. Allowances are assets. To "hoard" them deprives the company and its ratepayers of revenues and runs the risk that the value of allowances will decline over time as old, dirty facilities are retired.

Second, withholding allowances to save them for future growth can be a costly alternative that is not in the best interests of ratepayers because it would not minimize rates. The trading system provides better alternatives to hoarding to meet future growth, including allowance leasing (excess allowances could be leased

Answer 1
(Continued)

for a time period ending when new growth offsets are expected to be required) and offset contracts, whereby companies deal on a direct basis to purchase emissions directly from companies that have low marginal costs of emission control.

Third, high sulfur coal interests are best protected by an active emission trading system. Coal-fired plants will have the largest demands for allowances, and high sulfur coal-fired plants will have the greatest demands among coal-fired plants, until new technology can be applied. Without internally generated allowances, purchasing emission allowances will be the only alternative to paying for emission controls. A thin allowance trading market could drive up the price of allowances to the detriment of high sulfur coal users. This would encourage fuel switching (to low sulfur coal or natural gas) to the detriment of many high sulfur coal producers. Therefore, high sulfur coal producing and high sulfur coal using states will have a strong incentive to make sure that an active emission trading system exists.

Fourth, flow through of gains from sales of allowances to ratepayers should not prevent utilities from participating in the emission trading system. States will want their utilities to be good traders. This will not happen

Answer 1 (Continued)

without the proper incentives, and/or disincentives for failure to make good trades. Cost minimization is part of all utilities' strategies. Even if all benefits of trading go to lower utility rates, this helps the utilities remain competitive in competition with other fuels, and perhaps with other electricity providers, an important consideration to any utility manager.

Fifth, we do not believe that all utilities will be reluctant to invest in projects to control or overcontrol acid rain precursors because a state agency may disallow all or part of the investment as imprudent. A future buyer of allowances may be willing to foot the upfront costs of additional controls. Again, we think it is wrong to assume that all state agencies will act irrationally. As we already have stated, and as the State of Ohio already has recognized, it can be in the state's and utility's best interests to "in effect, overcomply, with the law." Moreover, there are mechanisms that states and utilities can use to minimize the risk of demonstrating new technology while protecting ratepayer interests. These mechanisms, including prudence preapproval, are described in sections 515(b)-(c) of the President's proposed legislation.

Answer 1
(Continued)

Lastly, it is not necessary that every company or state agency act in an economically rational manner for a successful emission trading system to emerge. The market for allowances is big enough to tolerate irrational behavior on the part of some parties.

Once in place, the President's Clean Air Act program will provide a long-term strategy for dealing with air quality issues. Although no one, least of all we, can bind future Congresses and future Administrations, the history of Clean Air Act revision suggests that clean air regulation will not be revisited frequently or easily. Thus, we believe there will be sufficient regulatory stability to allow the emission trading system to develop and operate effectively.

QUESTIONS FROM SENATOR JOHNSTON

Question 2(a):	**Summarize the impacts S. 1630 would have on U.S. coal markets, including total coal use, prices and quantities of different types of coal, coal imports, and coal-related employment.**
Answer:	The Department has not conducted any detailed analysis of S. 1630, but we believe that its coal market impacts would be similar to impacts from S. 1490, which has been evaluated by several groups. In general, these analyses indicate that the total tonnage of coal use would not be dramatically reduced by the legislation, but that distribution of the production would be affected. High sulfur coal production from the Midwest and Northern Appalachia would be displaced by low sulfur coal production from Central and Southern Appalachia. Typical projections for the year 2000 are about 100 - 120 million tons of coal production shifting regions, about 10% of total national production in 2000. Local impacts are somewhat greater: Northern Appalachia loses about 25% of it projected mining activity; the Midwest loses about 45%. In their analysis of the Administration's bill for EPA, ICF, Inc., estimated that natural gas could gain an additional quad of market by 2010, with most of it coming from a reduction in projected oil

Answer 2(a)
(Continued):

consumption by utilities --much of it imported oil. This would equate to a 20% increase in utility gas consumption relative to levels projected without acid rain legislation. ICF concluded that the total tonnage of coal production would remain almost the same under any of the scenarios which they evaluated.

DOE has reached a slightly different conclusion than EPA/ICF with respect to reduction in coal production. EIA evaluated utility fuel choice decisions under a spectrum of analytical assumptions at the request of Rep. Dingell.1/ One of the sensitivity analyses evaluated the effect of increasing coal costs by 10 percent over baseline conditions. DOE estimates that S. 1490 will increase the cost of producing electricity from coal by approximately 5-8 percent. Therefore, the EIA analysis offers some insight into potential fuel use impacts of S. 1490, and similar legislative proposals, in the year 2000. For a 10 percent increase in coal costs, the study concluded

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1/ Electricity Generation from Natural Gas: Prospects and Implications for the United States, EIA (SR/EPD/89-01), January 1989.

Answer 2(a) (Continued): that natural gas use would increase about 10 percent (above the 2000 baseline) and coal use would decrease about 4 percent (roughly 30-40 million tons per year). Electrical generation by oil, nuclear, and hydro energy was largely unaffected by the increase in coal use costs.

Question 2(b): **Evaluate the reasonableness of the assumptions regarding coal markets in the ICF analysis of the Administration's original proposal, particularly the price movements of low sulfur coal.**

Answer: ICF's analysis is predicated on the use of a model subroutine which predicts how prices will change for coal as demand for certain types of coal increases. This aspect of their model is similar to subroutines in models used at DOE, Argonne National Laboratory, and by others. It is a reasonable approach to the issue, but the results must be taken as an educated estimate because similarly high levels of demand for low sulfur coal have not been experienced in the past.

Question 2(c): **The ICF analysis stated that it "did not assess the potential penetration of low sulfur imported coals. These could be very competitive at the higher forecasted low sulfur coal prices in certain Eastern markets..." (p. 31). What is this potential? How does it affect the answers to the question above?**

Answer: Coal imports and exports could be affected by acid rain legislation. Most U.S. coal traded on international markets is low in sulfur, so any

Answer 2(c) (Continued): increase in the cost of this coal could decrease U.S exports. With respect to imports, Colombia and Venezuela shipped 1.4 million tons of coal to the U.S. in 1988, and EIA projects that level to rise to 7 million tons per year by 2000 (less than 10% of total U.S. coal consumption)2/. The cost of the Venezuelan and Colombian coal in 1988 averaged about $26 per ton (free at shipside), but prices in 1989 have gone up to about $35 per ton. It cannot be overemphasized that these prices are extremely sensitive to fluctuations in the value of the dollar relative to other currencies.

EIA data indicate that 1% sulfur coal sold in the U.S. for roughly $40 per ton (delivered) in 1988, although regional variation in price is very large. Acid rain models predict low sulfur coal prices would increase about 10% as the result of acid rain legislation. Hence, depending on world coal market conditions, the value of the dollar relative to other currencies, and transportation costs to specific power plants, imported coal could become

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2/ Annual Prospects for World Coal Trade - 1989, DOE/EIA-0363(89).

Answer 2(c) (Continued): more competitive with domestic low sulfur coal. DOE has not evaluated the degree to which foreign coals are likely to penetrate the U.S. market under an acid rain control scenario.

QUESTIONS FROM SENATOR JOHNSTON

Question 3(a): Summarize the impacts S. 1630 would have on U.S. gas markets, including total use, price, quantity, and imports.

Answer: S. 1630 is likely to increase the demand for low-emissions generating technologies such as gas-fired combined cycle generation and the use of gas to cofire coal boilers. Consequently, some increase in natural gas consumption by the electric generation sector would be expected under S. 1630.

However, natural gas use for electric generation has been expected to become increasingly competitive with respect to alternative fuels in many locations in baseload and intermediate load applications, even without S. 1630. For example, the EIA Annual Energy Outlook (1990 Draft) base case projects that natural gas consumption by electric utilities will more than double from 1988 to 2000, from about 2.6 trillion cubic feet (tcf) to about 6.2 tcf.

While DOE has not attempted to model the

Answer 3(a)
(continued):

impact of S. 1630, we believe that any incremental consumption of natural gas as a result of S. 1630 is likely to be relatively small, especially in terms of total natural gas consumption (18 tcf in 1988, 22.9 tcf in 2000). We expect S. 1630 to have an impact on gas consumption similar to that of the Administration's bill. In one of four scenarios analyzed, ICF estimated that the Administration's bill would result in an increase in gas consumption of approximately 0.5 quad in 2005 and almost 1.0 quad increase in 2010.

ICF assumed that each 0.5 quad increase would increase natural gas prices by 5 cents/MMBTU. Recent DOE estimates of the natural gas resource base suggest that the price effects of increased gas consumption due to S. 1630 would probably be modest. DOE's _An Assessment of the Natural Gas Resource Base of the United States_ [DOE/W/31109-H1, 1988] showed that technological developments, such

Answer 3(a)
(continued):

as non-uniform well spacings, could yield considerable additions to economically recoverable reserves at very small incremental production costs.

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There are a few other estimates of the price impact of increased utility consumption of natural gas. The Energy Modeling Forum at Stanford University published a comparison of natural gas industry models in 1989. While not directly modeling either the Administration's bill or S. 1630, it reported an average price effect for a 0.5 quad increase in consumption in 2010 of $.22 per mcf for the six models compared. Since many models participating in the EMF comparison exercise assumed a strong linkage between gas prices and residual fuel oil prices, the price impact may result more from their assumption of high oil prices than from the elasticity of the gas resource base. Moreover, the typical increase in utility gas consumption was assumed to be approximately

Answer 3(a)
(continued):

2.8 quads, almost three times the increase projected by ICF. Thus, the larger gas price increases may be due in part to higher assumed demand levels.

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Given the difficulties inherent in projecting price responsiveness of producing gas fields not yet discovered, and subject to further analysis, these estimates constitute a reasonable range of possible outcomes.

Although DOE has not yet evaluated gas market impacts of S. 1630 in detail, a DOE/EIA study entitled Electricity Generation from Natural Gas: Prospects and Implications for the United States [SR/EPD/89-01, Jan. 1989] determined that if the cost of generating electricity from coal were to increase by 10%, then in the year 2000 natural gas consumption in the utility sector would increase by approximately 12% in response.

DOE expects the impact of S. 1630 on gas

Answer 3(a)
(continued):

markets to be similar to the impact of the Administration bill (S. 1490). In that case, DOE estimated that the cost of burning coal would be increased approximately 8%, suggesting that natural gas consumption would increase by less than 10%.

Similarly, we would expect relatively insignificant changes in the volumes of gas imports solely as a result of clean air legislation. EIA projects that imports will rise from 1.2 tcf in 1988 to almost 3 tcf in 2010, without the incremental increase in gas consumption that may result from clean air legislation. A 1.0 tcf increase in utility sector consumption due to acid rain legislation in a total market of nearly 23 tcf would not be expected to have a significant impact on imports.

QUESTIONS FROM SENATOR JOHNSTON

Question 3(b): Evaluate the reasonableness of the assumptions regarding gas markets in the ICF analysis of the Administration's original proposal, particularly the estimate that for each additional 0.5 quad increase in gas demand, the price will increase by 5 cents/MMBTU (p. 30) and the estimate that in the High Case, the Administration bill would increase gas bills to non-utility customers by $0.8 billion per year.

Answer: The Department of Energy has not yet completed an independent analysis of the price effects of increased natural gas consumption due to acid rain legislation. ICF's assumption that a 0.5 quad increase in consumption in any given year will bring forth a $0.05 increase in price is not inconsistent with the results of DOE's An Assessment of the Natural Gas Resource Base of the United States [DOE/W/31109-H1, 1988]. That study showed that technological developments, such as non-uniform well spacings, could yield considerable additions to economically recoverable reserves at very small incremental production costs.

However, there are other reasonable views of

Answer 3(b)
(continued):

this matter. The Energy Modeling Forum at Stanford University published a comparison of natural gas industry models in 1989. The reported average price effect for a 0.5 quad increase in consumption in 2010 was $0.22 per mcf for the six models compared. Since many models participating in the EMF comparison assumed a strong linkage between natural gas prices and residual fuel prices, EMF's average price impact projections may result more from their assumption regarding high oil prices than from the inherent elasticity of the natural gas resource base.

Given the difficulties inherent in projecting the future price responsiveness of producing gas fields not yet discovered, and subject to further analysis, DOE believes ICF's assumption to be reasonable.

ICF's estimated $0.8 billion per year increase in gas bills to non-utility customers follows directly from their

Answer 3(b)
(continued):

assumption of a 5 cents/MMBTU price increase and their projected non-utility natural gas consumption of 15 to 16 quads in the period 2005-2010. The draft of the EIA's Annual Energy Outlook-(1990 Draft) estimates that non-utility consumption in the year 2010 will be 14.7 quads. Thus, ICF's projection of non-utility consumption is consistent with EIA's projection.

QUESTIONS FROM SENATOR JOHNSTON

Question 4(a):	Summarize the impacts S. 1630 would have on U.S. oil markets including total use, price, quantity, and imports.
Answer:	The amount of oil used for electric generation is relatively small although the in the past two years it has grown rapidly. The three major regions that use oil-fired electric generation--New England, the Mid-Atlantic, and the South Atlantic (primarily Florida)--use varying amounts of high and low sulfur residual oil. The New England and South Atlantic areas tend to use oil with the highest sulfur content (1.3 and 1.1 percent on an annual average). Oil used for electric generation in the Mid-Atlantic region is typically lower in sulfur content (.7 percent). In 1988, oil-fired electric power generation accounted for only 6 percent of total electricity generation. However, this represents a 24 percent increase over the 1987 levels in use of oil to

generate electricity. The first three quarters of 1989 show a 15 percent rise

Answer 4 (a)
(continued):

over the same time period in 1988.

The ICF analysis of S. 1490 indicates that, by the year 2010, if SO2 and NOx emissions reductions such as those found in S. 1490 were implemented, natural gas consumption for electric generation could increase by 1 quad (quadrillion Btus) over the base case without such legislation. This increased use of natural gas for electricity generation would backout approximately 470,000 barrels of residual oil per day. This reduction of oil for electric generation would affect both high and low sulfur residual oil. It is not likely that this relatively small reduction in demand for oil, spread over a 20-year period, would have any measurable effect on the price of oil.

The Department has not yet completed an independent analysis of the effect of S. 1630 on the oil market, but we do not expect the impacts of S. 1630 to be substantially different from those of S. 1490.

QUESTIONS FROM SENATOR JOHNSTON

Question 4(b): To what extent are prices in the oil and gas markets linked? Evaluate the reasonableness of the assumptions regarding oil markets in the ICF analysis of the Administration's original proposal, particularly regarding the extent to which gas price increases lead to oil price increases.

Answer: Linkage in the oil and gas market generally means that oil price changes may affect gas prices and vice-versa. This linkage arises because oil and gas can substitute for each other in many significant applications. A December 1988 study by the Department of Energy's Energy Information Administration (EIA) on fuel switching in the year 1985 indicates that the range of fuel switching between gas and other fuels (mainly fuel oil) by manufacturing establishments capable of switching within 30 days using only existing equipment was 2.5 trillion cubic feet, or 14% of the 1985 gas market.

The existence of a linkage, however, does not mean that oil and gas prices will be equal on a BTU basis. Sometimes gas has been priced higher than oil and sometimes oil has

Answer 4(b)
(continued):

been priced higher. Historically, there has been no simple relationship between oil and gas prices. As a consequence, it is difficult to determine the extent to which these prices will be linked in the future.

In its analysis of the Administration's original proposal, the ICF assumptions comport with this view. ICF assumes not only that oil and gas prices are uncertain but that the relationship between gas and oil prices is uncertain as well. ICF deals with this assumed uncertainty by using two classes of scenarios. In one, gas prices exceed oil prices and in the other, gas prices are less than oil prices. That is probably a more reasonable approach than the assumption made by some forecasters that gas prices will always be at or below oil prices.

ICF's assumptions regarding oil market prices also appear reasonable. Their high and low emissions cases forecasts of oil prices in

Answer 4(b)
(continued):

the year 2000 are $22.00 and $29.00 (in 1988 dollars). The draft EIA 1990 base case forecast for the year 2000 is $26.60 (in 1988 dollars). ICF's high and low emissions cases forecasts for 1995 are $18.00 and $25.00 (in 1988 dollars), while EIA's base case forecast for 1995 is $19.50 (in 1988 dollars).

The gas price assumptions made by ICF also appear reasonable. ICF's prices for gas delivered to utilities in the year 2000 range between $3.90 and $4.60 per mmBTU (in 1988 dollars) across the regions of the U.S. in the high and low emissions cases, while EIA's base case forecast for 2000 is $3.67 (1988 dollars).

Question 4(c): To what extent would the Administration bill increase oil costs to non-utility customers due to upward pressure on oil prices?

Answer: Although we are continuing to analyze this issue, we do not anticipate that the acid rain provisions of the Administration's Clean Air proposal would cause upward pressure on oil prices. The ICF analysis of the proposal indicates a reduction in utility sector demand for residual oil. A reduction in demand would signify downward pressure on the price of residual oil for non-utility customers.

QUESTIONS FROM SENATOR JOHNSTON

Question 5(a): Summarize the impacts S. 1630 would have on U.S. electricity markets, including total use, price, quantity, and imports.

Answer: To date, the Department of Energy has conducted no definitive analysis of S. 1630. However, we believe that its electricity market impacts would be similar to impacts of S. 1490.*

Based on EPA estimates of 1.2% to 1.8% average electricity rate increases and EIA estimates of long-run price elasticities (i.e., the percent change in consumption in response to a one percent change in price), we estimate that the Administration's proposed acid rain legislation would reduce electricity consumption by approximately 0.46% to 0.74%, or about 16.0 billion to 25.7 billion KWH in the first year of Phase II.

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* To the extent that S. 1630, compared with S. 1490, accelerates the compliance dates for Phase I and Phase II, it may raise compliance costs and, therefore, utility rates. The earlier compliance dates will raise the present value of costs. In addition, the more stringent NO_x reduction requirements of S. 1630 will raise compliance costs.

Answer 5(a) (continued):

DOE has not explicitly modelled the effects of acid rain legislation on electricity imports from Canada. EIA has projected that net electricity imports in 2000 will be 72.7 billion KWH witnout any new acid rain legislation, up from 31.8 billion KWH in 1988. Acid rain legislation will have an uncertain, but likely small, effect on electricity imports.

To the extent that S. 1630 will raise the cost of coal-fired electricity, Canadian power imports may increase on the margin to regions that currently generate the majority of their electricity with coal. Currently, nearly all Canadian electricity exports go to the Northeast and West Coast, regions that produce most of their electricity from non-coal sources (predominantly hydro and oil). Imports by Ohio Valley utilities may be constrained by unfavorable comparative economics as a result of the need for long

Answer 5(a)
(continued):

distance transmission, as well as actual transmission capacity limitations. In addition, it is uncertain whether Canadian electricity boards would permanently commit capacity to U.S. markets or simply engage in contract sales of power for relatively short time periods until Canadian demand catches up with capacity additions.

QUESTIONS FROM SENATOR JOHNSTON

Question 5(b): Electricity Market Impacts In testimony before the House Subcommittee on Energy and Power, Deputy Secretary Moore stated that "the cap would cost about $2 billion per year and add 2-3 dollars per megawatt-hour to cost of power from new plants (about five percent)." [p. 17] Provide the assumptions, methodology, and derivation of these estimates.

Answer: DOE's estimates of the impact of the cap provision applied to long term impacts (i.e., in the 2020 to 2030 time frame). They are relatively simple and straightforward. However, it should be pointed out that near term impacts (i.e., 2000 to 2010) would be much less, because marginal costs will be lower in the near term (perhaps one-half as much as assumed for the long term), and because there are relatively few new sources requiring offsets in the near term, due to the availability of conservation and low emission energy sources such as solar technologies and natural gas technologies.

The analysis leading to an estimate of $2 billion per year as the cost of the cap in the year 2030 is as follows:

Emission allowances were calculated for each coal unit in the US, based on explicit

> allowances or implicit allowances assuming a 65% capacity factor in 2000 and 2030.
>
> New capacity was introduced assuming a 3%/year growth in coal-based generation demand after 2000. New capacity was assumed to emit 0.3 #SO2/mmBtu, half the current NSPS allowable rate. Old capacity was retired assuming a 60 year life.
>
> Considering growth and retirements, utility emissions would have grown by 1.3 million TPY by 2030, absent additional reductions on pre-2000 units. Hence, a 1.3 million TPY reduction was needed.
>
> A marginal cost of reduction of $1500/ton SO2 was assumed to be reasonable for this range of additional control. $1500/ton x 1.3 million TPY = $2 billion per year.

The cost of power calculation for a specific plant also was calculated for a plant built in 2030, as follows:

> The emission rate to be offset was assumed to be 0.3 #SO2/mmBtu, as above. Assuming a heat rate

typical of today's power plants (10 million Btu/MW-hr), this results in 3 #SO2/MWhr of electricity.

The marginal cost of controlling existing units in 2030 was assumed to be $1500/ton SO2, or $0.75/pound SO2.

The impact on the cost of power = 3 #SO2/MW-hr x $0.75/#SO2 = $2.25 /MW-hr. ($2-3 per MW-hr was offered in the testimony to represent some of the uncertainty inherent in the estimate.) The baseline cost for electric power from a new plant is about $50/MW-hr.

As noted above, the marginal cost of control assumed for this estimate was one appropriate for the long term. A near term marginal cost of control might be one-half as much, which would lead to cost offsets for new plants built in 2000-2010 of only one-half as much as estimated for the long term.

Question 5(c): Is the marginal cost of emission control expected to change over time? Why or why not? Illustrate expected changes by providing estimates of the marginal cost per ton of emission reduction for the following control options in roughly the 2000 and 2010 time frames:

1) a decision to go beyond NSPS standards in a new plant by removing more than 90% of SO2 through advanced scrubbing or repowering technology (i.e., what is the cost of the increment of emission reduction above 90%)?;

2) a decision to reduce emissions by coal switching at an existing plant;

3) a decision to install scrubbers of clean coal technology at an existing plant; and

4) other options (specify).

Expand on these examples in any way that illustrates how control costs change over time.

Answer: The marginal cost of control will change over time. The greatest change will likely occur between 1995 and 2000. In 1995, low sulfur coal will likely be adequate to meet most compliance requirements. However, the greater reductions required by 2000 cannot be met by coal switching alone. Utilities will be forced to use more efficient, and expensive, control techniques, such as scrubbing. Scrubbing typically costs much more per ton of SO2 removed than switching from high sulfur coal to low sulfur coal.

Three other, less dramatic trends are important to note, especially for the 2000 - 2010 time frame. They are: (1) the effect of the cap, which forces greater and greater reductions over time, as offsets for new sources; (2) the constant evolution of technology, which can be accelerated by government R&D and technology demonstration projects, and (3) the turbulent market which will immediately follow enactment of acid rain control legislation, which will likely lead to temporary runups in the cost of low sulfur coal as well as scrubbers.

1) Pushing conventional scrubbers beyond 90% is possible with use of additives, such as dibasic acid, and with use of alternative reagents, such as sodium, instead of limestone. Conventional (90% removal) scrubber costs estimated by ICF/EPA appear to average about 7.5 mills/kwh (levelized 1988 dollars for a large, high sulfur coal retrofit), and ICF reports that a 95% efficiency could be attained with an additional 0.4 to 0.8 mills/kwh3/. Assuming one starts with a 6#SO2/mmBtu coal, and a heat rate of 10 million Btu/Mw-hr, increasing the removal rate to 95% eliminates 0.3#SO2/mmBtu at a cost effectiveness (CE) of $270 to $540 per ton of SO2 captured. At 7.5 mills/kwh, the CE of the first 90% reduction would be about $280/ton SO2. Hence, the cost effectiveness of controlling from 90% removal efficiency to 95% may be twice as high, or alternatively, about the same, as the cost effectiveness of achieving 90% control

> with conventional technologies, depending on which cost estimates you believe are more nearly correct. In either case, it should be noted that the cost of electricity from the plant is not sharply increased by selecting the more efficient approach. Generation costs for a retrofit unit with uncontrolled costs of 30 mills/kwh would increase about 25% to achieve 90% control and about 28% to achieve 95% control.

Retrofit scrubbing of a low sulfur coal plant would cost less per kwh, but more per ton reduced, because less SO2 is reduced per unit of energy. Overall CE for a large low sulfur coal fired plant might be $1100/ton SO2.

Scrubbing at smaller plants generally costs more than scrubbing at large plants. For example, scrubbing a 200 MW high sulfur coal plant costs more than 50% more per ton of SO2 removed than scrubbing a 500 MW high sulfur coal plant.

Over time, it will be necessary for utilities to apply scrubbers at fewer and fewer cost effective sites (older, smaller, lower sulfur units).

2) The cost of switching coals at existing plants is sensitive to the geographic location of the plant and the stringency of the control program. In some eastern areas, low sulfur coal carries a high premium. In some western areas, little or no premium exists. In Federal Region V (the Midwest), we estimate that the premium for a switch from high sulfur coal to low sulfur coal will be about $0.50/mmBtu of coal, which converts to a cost effectiveness value of $230/ton SO2 reduced.

3) As noted above, the cost of retrofitting 90%-efficient scrubbers at a large high sulfur coal plant is about $280/ton SO2. This estimate reflects the recent decline in control costs as the technology has matured. Cost estimates in the early 1980's were about 60% more than this figure for similar conditions. We believe that the downward trend in costs will continue. If the CCTP is successfully completed and appropriate deployment incentives are adopted, then we would expect to see costs decline from today's estimates by about 25% by 2000 and as much as 50% by 2005. These levels of CE ($140/ton and $70/ton, respectively, at a large, high sulfur coal plant) would make technology

options very competitive with fuel switching at such plants.

4) Because the SO2 emission cap requires utilities to offset emissions from new sources, the emission rate of new sources is important to understanding cost effectiveness trends over time. If extremely advanced technologies are used, then SO2 emissions from new sources in the future could be one-sixth the level of today's new source emission rates. Offsetting this small level of emissions could be managed largely through expected retirements of older power plants, leading to constant or even declining control costs for the nation. However, if only "very good" technologies are used at new coal plants, with emissions which are still 50% below rates from today's new plant technologies, then SO2 reductions from retirements will not keep pace with SO2 increases from projected new units, and the marginal cost of control could increase over time.

QUESTIONS FROM SENATOR JOHNSTON

Question 6:	Provide estimates of the following by state for the period 1990 to 2010: electrical demand growth, electric capacity additions, and electric capacity reserves.
Answer:	The EIA draft base case for the 1990 Annual Outlook for Electric Power projects the following demand, capacity, and reserve figures for the 1990 to 2010 time period (data is available for the ten Federal Regions only, not at the state level):

ELECTRICITY SALES -- 1988 to 2010
(in Billion Kilowatthours)

	1988	1990	1995	2000	2005	2010
New England	102	108	127	145	162	180
NY/NJ	188	201	234	265	297	330
Mid-Atlantic	270	280	318	356	393	437
South Atlantic	555	566	633	710	783	864
Midwest	492	504	586	666	739	821
Southwest	360	371	415	465	511	562
Central	124	134	156	176	195	215
North Central	81	88	102	115	128	141
West	261	283	334	387	435	488
Northwest	145	155	180	204	226	249
US	2,578	2,689	3,083	3,488	3,870	4,288

Answer 6
(continued):

CUMULATIVE UTILITY CAPACITY ADDITIONS -- 1990 to 2010
(in Gigawatts)

	1990	1995	2000	2005	2010
New England	1.2	2.6	5.3	8.4	12.6
NY/NJ	0.0	3.3	10.5	17.8	26.0
Mid-Atlantic	0.3	4.9	14.3	22.8	32.3
South Atlantic	0.5	10.7	13.8	25.1	43.7
Midwest	0.0	5.6	24.8	41.7	61.3
Southwest	1.4	6.7	10.4	15.1	26.4
Central	0.2	3.9	9.9	15.3	20.9
North Central	0.1	0.6	3.2	5.5	8.0
West	0.4	3.5	14.4	24.8	36.0
Northwest	0.0	0.2	2.5	6.3	10.2
US	4.0	42.2	109.2	182.8	277.3

ELECTRICITY CAPACITY RESERVE MARGINS -- 1988 to 2010
(percent)

	1988	1990	1995	2000	2005	2010
New England	25	25	15	17	15	15
NY/NJ	37	28	16	15	16	15
Mid-Atlantic	25	24	15	15	15	15
South Atlantic	43	41	33	20	15	15
Midwest	34	32	15	15	15	15
Southwest	43	46	34	23	15	15
Central	26	22	15	15	15	15
North Central	30	27	18	15	15	15
West	47	35	16	15	15	15
Northwest	56	46	27	20	20	20
US	40	37	24	19	17	17

QUESTIONS FROM SENATOR JOHNSTON

Question 7(a): What is the rationale behind each of the specific regulatory incentives included in section 515 of S. 1490? How will these incentives reduce risk for users of clean coal technologies? Will increased use of clean coal technologies result from inclusion of regulatory incentives? How much generating capacity do you expect will utilize clean coal technology by 2000? By 2005?

Answer: Rationale For Each Incentive

For Repowered Sources

- Three-year extension from meeting 12/31/2000 compliance deadlines (section 508 (b)) is provided because the repowering technologies are not projected to be available for commercial operation until at least 2003.
- Relief from compliance with new source review (NSR) procedures (Section 508(c)) is provided because:
  (1) The procedures are not necessary. The emission allowance trading program and emission cap provide an incentive for new units to emit at a very low rate - rates lower than required by even the revised NSPS.
  (2) NSR procedures are time consuming and lead to significant expense.

Answer 7(a) Continued:

(3) Technology demonstration is essential to hasten the development of superior emissions control technologies. (4) Incentives will encourage more rapid deployment and reduce emissions of other pollutants.

o The alternative allowance system option (section 508 (d))

- Besides allowing repowered sources to obtain allowances like all other existing sources, an alternative allowance system is offered. Since repowered sources would increase the power output of the repowered plant, the optional system would require the added capacity to meet New Source Performance Standards (NSPS) and the original capacity to meet the allowance system all other existing sources must meet.

- Section 508 (d) is essential to provide a sufficient number of allowances to repowering units which have run at very low capacity factors prior to repowering (have a low Btu baseline). Repowered capacity is still subject to stringent control (i.e., the current President's bill; the new capacity would meet NSPS).

Answer 7(a)
Continued:

For All Clean Coal Technologies (CCTs)

- The following regulatory incentives for FERC regulated utilities (section 515) are offered:
  - Incentive rate of return on the risky investment in CCTs. An incentive rate of return can be established whereby a relatively high risk project that improves the economics of controlling emissions will be rewarded by being given a higher than normal rate of return on that project.
  - Ten to twenty year amortization to recover the capital costs of a risky project more quickly (section 515(b)(1)(B)).
  - Preapproval of prudency for CCT project costs if the costs fall within previously negotiated caps (section 515(c)).
- The following additional incentives are provided.
  - Relief from WEPCO ruling (i.e., relief from new source review procedures) for projects funded under DOE's CCT Demonstration Program or similar EPA programs (section 515(d)).

Answer 7(a)
Continued:

- Encouragement to states to adopt incentives for projects using CCTs (section 515(e)).

o These incentives are provided because:

(1) The CCTs offer significant economic, environmental, and energy benefits as compared to conventional coal-based technologies.

(2) Since the technologies are not in commercial use today, a boost is needed to compensate for the risks inherent in new technologies and provide limited rewards for accelerating their movement to commercial readiness.

(3) The WEPCO ruling at present threatens to prevent many CCT demonstrations from going forward, because of the possibility that unexpected and costly additional controls will be required solely because of the CCT demonstration.

Question 7(b): How will these incentives reduce risk for users of CCTs?

Answer: The incentives for repowering technologies will reduce or compensate for risk by:

Answer 7(b)
Continued:

(1) better ensuring that the technologies will be technically proven and ready for commercial use,

(2) eliminating the regulatory uncertainties associated with the EPA's WEPCO decision, and

(3) clarifying the allowance system for technologies which not only reduce emissions, but increase power output at the same time.

The incentives for all CCTs will reduce risk by:

(1) providing utilities rates of return which are commensurate with their investment in these risky, but potentially advantageous technologies,

(2) reducing some of the financial risks associated with investment in first-of-a-kind technology, and

(3) eliminating the regulatory uncertainties associated with the EPA's WEPCO decision.

Question 7(c): Will increased use of CCTs result from inclusion of regulatory incentives?

Yes. It is the intention of the incentives program to encourage the construction and operation of a variety of CCTs to demonstrate that they can operate reliably, cost-effectively, and meet environment requirements--all important factors in electric utility decision-making. As each type of technology is successfully operated, the door will open for their widespread commercial use.

Question 7(d): How much generating capacity do you expect will utilize CCT by 2000? By 2005?

That is difficult to answer. The answer will be dependent upon a number of factors including:

- cost and availability of fuels in competition with coal, especially natural gas,
- the success of the CCT Demonstration Program,
- the compliance deadlines and stringency of whatever acid rain legislation is passed, and
- whether the WEPCO decision continues to have a chilling effect on the CCT program.

Very little new capacity between now and 2000 will use advanced generation techniques, but advanced abatement technologies might be used on one-half of the new conventional coal generation plants (5-10 gw of abatement capacity). From 2000 to 2005, it would be reasonable to expect a maximum of one half the total unplanned coal capacity projected to use advanced generation technology (25-30 gw) and one-half of the conventional generation to use advanced abatement technology for SO_2/NO_x cleanup (another 25-30 gw).

Answer 7(d) Continued:

With respect to existing capacity retrofits, the contribution of repowering technologies is subsumed within the new capacity estimates above. Retrofit CCT abatement technologies could account for 25-50% of the technology installed for the 2000 compliance deadline. Estimates of the likely amount of scrubbed capacity vary between analysts. EPA/ICF projects 15-30gw of retrofit scrubbers by 2000; EEI/TBS estimates 60-75 gw. This limited sampling of estimates yields a CCT retrofit potential of 4-37 gw of scrubbing capacity. However, if ongoing R&D and demonstrations are fully successful, even greater penetration of CCT's is possible, with greater use of technology and less use of low sulfur coal.

QUESTIONS FROM SENATOR JOHNSTON

Question 8: DOE has testified to the importance of replicating projects in order to reduce risk.

Question 8(a): What is the rationale for limiting the applicability of the incentives to a limited period of time or a limited number of demonstrations projects in the President's proposal?

Answer: The intent of the regulatory incentives is to encourage the construction and operation of a few of each of the large variety of types of CCTs to increase the private sector's confidence in them, thereby paving the way for their commercial deployment.

Question 8(b): How do you reconcile that apparent conflict in position?

Answer (b): There is no conflict in position. The incentives provided in the President's bill are intended to encourage enough CCT replication to build confidence that the technologies will work as advertised.

QUESTIONS FROM SENATOR JOHNSTON

Question 9(a): What was the purpose of ICTAP?

Answer 9(a): The purpose of ICTAP was to advise the Secretary of Energy on DOE's innovative control technology research, development, demonstration programs.

Question 9(b): What groups are represented on the ICTAP?

Answer: A wide variety of groups are represented including:

- State electric utility regulators
- State environmental regulators
- State energy offices
- Federal agencies (OMB, Interior, EPA, State, Commerce, Energy)
- Electric utilities
- Coal producers
- Public interest groups (e.g., environmental, labor)
- Canadian Energy and Environmental Ministers

Question 9(c): What extent was this group consulted in the formulation of the President's legislation?

Answer: The group, as a whole, was not directly consulted in the formulation of the President's legislation. Individuals of the group (e.g., federal agencies and likely others) were consulted. Most importantly, however, relevant ICTAP studies were considered by those who were involved in drafting the bill.

Question 9(d): To what extent were ICTAP's recommendations adopted in the President's bill?

Answer 9(d). To a significant extent.

ICTAP's "Report to the Secretary of Energy Concerning Commercialization Incentives" provided a listing of possible incentives that should be considered. All of the regulatory incentives proposed in the President's bill were among those included in the ICTAP report. Even the "encouragement" of states to adopt incentives followed the recommendations of ICTAP the Federal Government avoid telling States what to do and how to do it.

Question 9(e). Does ICTAP have a position on the limitation of regulatory incentives to a limited period of time for a limited number of projects as in the President's bill?

Answer: ICTAP's position is that incentive programs (both federal and state) should be limited to the demonstration and pre-commercial deployment stages. They point out that once a technology reaches the commercialization stage, it should compete with other energy alternatives in a free market, without the use of incentives.

Answer 9(e)
Continued:

Therefore, the limitations placed on the incentives in the President's proposal are similar to those recommended by ICTAP.

QUESTIONS FROM SENATOR JOHNSTON

Question 10. In the July 11, 1989, hearing before the Subcommittee on Energy Research and Development, the Clean Coal Technology Coalition provided its estimates for when clean coal technologies will be "available for commercial order" and when these technologies will be available for "potential widespread commercial use to achieve reductions of air pollutants."

Question 10(a): Does DOE agree with the estimates and assumptions presented by the Coalition?

Answer 10(a): Generally speaking, DOE agrees with the Coalition's assessment that after initial demonstration, a few replications will be required to provide assurances of reliability, operability, cost, and performance required by electric utilities to commercially deploy any advanced technology.

The specific timelines that either the Coalition or DOE could provide showing when the technologies would be available for widespread deployment is judgemental and dependent upon a number of factors including:

- the stringency and compliance deadlines of acid rain legislation,
- the cost and availability of competing fuels, especially gas,
- the complexity of the technology,
- the stage of development of the technology,
- the costs associated with the technology, and
- the willingness of utilities and utility regulations to take risk.

Answer 10(a) Continued:

Specifically, however, DOE's assessment of the dates for commercial deployment of various CCTs is:

- retrofit NO_x controls from 1994-2000,
- retrofit SO_2 controls from 1994-2002, and
- repowering:
  - -- atmospheric fluidized-bed 1996-2000 -- pressurized fluidized-bed 2002-2005
  - -- integrated gasification combined cycle 2003-2005.

In general, DOE is somewhat more optimistic than the coalition. However, depending upon the above factors as well as factors as of yet unaccounted for, either or neither of us could be correct.

These estimates are based on the professional expertise and judgement of DOE engineers and scientists. The only documentation DOE has to support these estimates is the timelines of specific CCT projects and estimates of additional time that would be required to make the technology commercially deployable after demonstration.

QUESTIONS FROM SENATOR JOHNSTON

Question 11(a): Please provide a detailed analysis of the economic, energy and environmental benefits of repowering technologies.

Answer: The following table provides a comparison of the cost and performance of a conventional pulverized coal boiler with a scrubber vs. the expected values for several advanced repowering technologies once they have become commercially proven. These figures are highly speculative at this time and should be used with great caution:

COAL TECHNOLOGY
COST AND PERFORMANCE VALUES (1988 $--FIRST YEAR)

TECHNOLOGY	MW	$/KW	FOM1/ $/KW-YR	VOM2/ M/KWHR	HEAT RATE	YEAR AVAIL.
PULVERIZED COAL WITH SCRUBBER	500	$1,552	$28.20	6.50	10412	Commercial
PFB	500	$1,214	$40.47	2.85	7822	2005
IGCC	500	$1,087	$33.94	2.67	7940	2005
GASIFICATION STIG	500	$981	$31.75	2.51	8530	2010
COAL-FIRED TURBINE	500	$976	$43.44	4.04	10138	2010
MHD	500	$1,475	$16.00	2.40	6576	2010
MOLTEN CARBONATE FUEL CELL	500	$1,334	$28.50	6.40	7130	2010
SOLID OXIDE FUEL CELL	500	$1,115	$28.50	4.10	6000	2025

1/ FOM = Fixed Operation and Maintenance Costs

2/ VOM = Variable Operation and Maintenance Costs

Answer 11(a) Continued:

The energy benefits of the repowering technologies include:

- higher system efficiencies and therefore conservation of energy resources and less CO_2 emissions per unit of energy output.
- the ability to shop fabricate major system elements (for most of the technologies) thus reducing construction costs and capital costs.
- The ability to construct most of the technologies in modules, thereby reducing electricity demand projection uncertainties and reducing construction time and capital expenditures for unneeded capacity.

The environmental benefits include:

- significant SO_2 (up to 99+%) and NO_x (up to 95%) reductions
- reduced CO_2 emissions
- production of dry, easy to dispose of wastes or marketable by-products (e.g. sulfur and sulfuric acid).

Question 11(b):	Please provide a detailed analysis of the economic, energy and environmental benefits of various retrofit technologies representative of those selected by DOE for its CCT demonstration program.
Answer:	DOE has sponsored an analysis to estimate the least cost approach (consistent with the President's proposed CAA amendment) to reducing emissions of SO_2 by 10 million tons per year from existing U.S. utility boilers. Two scenarios were investigated. In the first scenario, the base case, it was assumed that utilities would either switch to low sulfur coal or use conventional flue gas desulfurization (FGD) to comply. In the second scenario, the utilities were free to choose from an array that included coal switching and conventional FGD plus a range of clean coal technologies (furnace sorbent injections, duct sorbent injection, advanced FGD, combined NO_x/SO_x cleanup), both alone and in combination with physical coal cleaning.

The methodology used to calculate the least cost means of complying with the required reduction consisted essentially of two steps. First, the cost of controlling emissions from each existing U.S. boiler (over 1000) was calculated and the lowest cost approach was chosen. Then, the results were summed (most cost effective boiler to control first) until the required reduction was achieved.

Since the intent of both scenarios was to reduce emissions to the atmosphere, the environmental differences between the two approaches were not significantly different, although the

Answer 11(b)
(Continued): clean coal case resulted in an increase in the production of solid waste. Also, the energy differences between the two cases were not significant, although there is a small energy savings in the second scenario when the clean coal technologies are used. The major differences between the two scenarios were economic as revealed in the table below:

	Base Case	Clean Coal Case
Capital Investment ($M)	19,300	10,800
Annual Cost ($M)	5,400	3,900
Cost per Ton Removed ($/Ton)	540	390

Not only did the clean coal case lead to a lower cost per ton of complying, it resulted in a major reduction in the capital investment required.

Specifically major cost reductions are achieved because currently available FGD is not competitive in the clean coal case. The reason is that in the base case, the average cost of conventional FGD was about $700 per ton. In contrast, the advanced FGD and combined NO_x/SO_x (both sorbent based and catalytic reactors were comparably competitive) are about 25% less costly. Sorbent injection (either directly into the furnace or into the duct) is also very competitive,

Answer 11(b) Continued:

costing up to one third less than conventional FGD (although these technologies were more competitive on relatively smaller boilers whereas advanced FGD and combined NO_x/SO_x were more competitive on larger units). Clean coal savings increase when the above technologies are used in combination with physical coal cleaning, and are reflected in the above estimates.

Question 11 (c) Provide a detailed analysis of the economic, energy and environmental benefits of natural gas co-firing technologies (including gas reburn).

Answer: There are over 1000 utility boilers that would be affected by the proposed acid rain legislation. To comply with the legislation, required SO_2 reductions on specific boilers would have to range all the way from several percent to over 90%. This implies that a variety of approaches need to be considered.

Natural gas co-firing could have a small but important niche. For a 10% gas substitution, SO_2 would be reduced by 10% and NO_x by 20%. For a large boiler burning 3% sulfur coal, and assuming a $2 price differential between coal and natural gas, the reduction (equating 1.5 lb NO_x to 1.0 lb SO_2) would cost $700/ton. While this is not necessarily an effective approach by itself, the technology could be desirable where other characteristics of co-firing are

Answer 11(b)
Continued:

important. Such would be the case if slagging or fouling were a problem that caused high maintenance costs which could be alleviated. In fact, for some units that switch coals to comply with the legislation, slagging or fouling could be a concern. Also, for smaller price differentials between coal and natural gas, the cost effectiveness of cofiring would be lower.

Gas reburn is a technique for staging combustion in a way to reduce NO_x. For example, for a 15% reburn substitution, SO_2 would be reduced by 15% and NO_x by 60% (the percent reduction for NO_x is so high because staging combustion is a very effective means to reduce NO_x formation. For applications where significant NO_x reduction are required, gas reburn promises to be an option that is economically competitive with selective catalytic reduction (i.e., it costs somewhat less per ton), and it requires a much lower capital investment. However, it is somewhat more limited in its ability to reduce NO_x (60% for reburn versus 80% for SCR). Coal reburning is projected to be slightly less efficient in terms of NO_x reduction than natural gas reburning (50% vs 60%) but should be more cost effective as a result of lower fuel costs. The costs for coal reburning are estimated to be on the order of 30-50% of the natural gas reburning costs on a dollar per ton of NO_x removed

Answer 11(c) Continued:	basis. However, assuming the same coal is used for reburning as in the primary combustion zone, there will be no associated SO_2 reduction as would be obtained with natural gas reburning.
	Another approach to NO_x reduction applicable to wall and tangentially fired boilers is combustion modification which incorporates techniques such as low NO_x burners and overfire air. Advanced versions of combustion modification techniques were selected for evaluation in the CCT program on wall-fired and tangentially-fired boilers. Depending on the degree to which modifications are incorporated, NO_x reduction potential is on the order of 50%. Corresponding capital requirements could range as high as for reburning. On a dollar per ton of NO_x basis, costs for combustion modification technology are estimated to be some 10% to 20% of the comparable costs for natural gas reburning.
Question 11(d):	What is the rationale for limiting the extension for clean air legislation for Phase II to repowering technologies?
Answer:	The extension was limited to repowering technologies because they appear to be the only technologies which will not be adequately proven to be considered for use in complying with the control requirements by 2000.

Answer 11(d) Continued:

If the Clean Coal Technology demonstration program runs smoothly and the projects are successful, several advanced retrofit technologies (e.g. sorbent injection, NO_x control and combined NO_x and SO_2 control) will be available for consideration by the mid to late 1990's.

QUESTIONS FROM SENATOR JOHNSTON

Question 12:	In response to a question from the July 11, 1989, Energy R&D Subcommittee hearing, DOE replied that "The fear that the WEPCO decision may provide a strong motive not to participate in the Clean Coal Program is a well founded one." What effect, if any, will the WEPCO decision, if left unclarified, have on the cost of compliance with the current New Source Performance Standards (NSPS) and/or the Prevention of Significant Deterioration (PSD) provisions under the current Clean Air Act?
Answer:	The effect could be dramatic. A successful Clean Coal Technology program could lead to control costs that are 25-50% less then today's technology options.

Electric utilities participating in our CCT Demonstration Program are very concerned that they may be penalized by being forced to control well beyond their present control requirements just because they host a CCT demonstration project.

In fact, one CCT project, the Appalachian Project, was terminated in part because of concern regarding the WEPCO decision. At least 9 other CCT projects are in jeopardy because of the requirement imposed by WEPCO.

As a result, language was included in the President's clean air legislation to remedy the problem. Noting that the WEPCO decision is currently affecting the CCT Program, DOE has urged EPA to issue immediately an interpretive ruling consistent with the language of the President's bill.

QUESTIONS FROM SENATOR JOHNSTON

Question 13. Is it possible that the WEPCO decision could affect the potential conversion of many oil units to gas (with potentially lower costs and emissions)? Conversion of coal-fired units to natural gas co-firing? If so, how?

Answer: Yes. In fact, such conversions have already been adversely affected.

EPA determines whether new source review (NSR) and New Source Performance Standards (NSPS) will apply based upon a comparison of the plant's actual SO_2, NO_x, and particulate matter emissions before conversion with "potential" emissions of those pollutants after conversion. If emissions are projected to increase, the converted plant would be subject to NSPS and NSR. For an oil or coal plant converted to natural gas, this could mean the need to install an expensive NO_x control device.

EPA defines "potential to emit" as the emissions that would result from the converted plant assuming that it would operate at full rated capacity day in and day out for a full year (which is very unlikely).

Therefore, even for an oil plant converting to natural gas (with likely lower emissions and lower costs) a comparison of actual NO_x emissions of the oil or coal plant and potential NO_x

Answer 13
Continued: emissions from the natural gas plant will likely show an increase in NO_x because of the low capacity factor of an oil plant used in peaking or cycling mode and high assumed capacity factor of the gas plant.

Question 14: On July 11, 1989, DOE testified that Integrated Gasification combined Cycle (IGCC) and Pressurized Fluidized-Bed Combustion (PFBC) technology should be "adequately demonstrated so as to be commercially available to the utility market" in the 2003-2005 timeframe. Since the proposed extension in the Clean Air Act proposals before the Congress is only until 2003, will this effectively shut out the use of these technologies for compliance?

Answer: Not necessarily. Both technologies have been selected under our CCT Demonstration Program. As a matter of fact, 3 PFB's and 3 IGCC's are currently a part of our Program.

If these projects proceed on schedule, they could be available for consideration to comply with the 2003 compliance deadline of the President's bill.

We admit the timelines are tight. However, the President balanced the urgency to reduce emissions with the projected availability of new technologies and came up with the December 31, 2003 compromise.

QUESTIONS FROM SENATOR JOHNSTON

Question 15:	Some have suggested various means of cost-sharing as a means for spreading the burden of compliance with any Clean Air Act Amendments nationwide. What mechanisms other than a tax or fee might help spread these costs? Does DOE have an analysis of typical electric bills for the ten states with the highest SO_2 emissions? For states and utilities that have significantly reduced SO_2 emissions since 1980? Please provide a state-by-state estimate of the average residential electric bill in each state and an estimate of the national average residential electric bill. Please cite the source of any data used in this analysis.
Answer:	The emissions trading system proposed by the Administration, in effect, spreads the costs of acid rain control in an equitable manner. In doing so, it not only minimizes the cost of cleanup for everyone, it provides the "dirtiest" utilities with an asset they can potentially sell: emission allowances. Under a strict rate approach, by contrast, every unit is required to make the same reduction, regardless of costs. There is no incentive to overcontrol because there is no economic benefit to doing so.

For the states with the highest emissions, Alabama, Georgia, Illinois, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Tennessee, and West Virginia, the attached Table 1 indicates typical monthly electric bills at the residential level of 750 kilowatt-hour (KWh) consumption for the years 1980 to 1988. The data were drawn from the

Answer 15
(Continued) Energy Information Administration (EIA) publication, Typical Electric Bills, which, in turn, obtains the data from EIA Form-213. For consumption at levels above or below the 750 KWh level, see the attached tables indicating a state-by-state breakdown of typical residential electric bills from 1980 through 1988.

There were ten states that reduced sulfur dioxide emissions by more than 20 percent between 1980 and 1987. These states and their percentage SO_2 reduction are:

California	100%	New Mexico	40%
Illinois	23	North Carolina	30
Kentucky	30	South Dakota	67
Minnesota	44	Wisconsin	36
Nebraska	33	Wyoming	42

Source: EIA, Annual Outlook for U.S. Electric Power 1989, Appendix Table C2.

The attached Table 2 indicates typical residential bills at the 750 KWh level from 1980 through 1988. The typical monthly electric bills data were taken from various issues of EIA's Typical Electric Bills.

Table 1

TYPICAL MONTHLY ELECTRIC BILLS--NATIONWIDE AND TEN STATES WITH LARGEST EMISSIONS

(Residential 750 KWh--Dollars)

	1988	1987	1986	1985	1984	1983	1982	1981	1980
National Average	57.39	56.78	58.79	57.86	54.76	52.74	50.07	43.99	36.94
Alabama	49.79	51.87	51.26	50.94	49.75	48.22	41.23	40.69	33.99
Georgia	49.49	46.13	46.07	45.38	44.58	41.06	38.97	33.06	30.08
Illinois	50.89	54.65	57.90	55.01	53.83	50.82	45.84	39.89	33.51
Indiana	58.49	58.84	56.12	54.12	52.30	47.35	42.72	37.19	35.22
Kentucky	39.81	42.31	42.44	42.14	40.34	38.14	36.36	32.00	27.71
Missouri	52.39	51.73	49.42	44.95	45.06	43.39	40.60	36.88	33.69
Ohio	61.09	61.80	59.92	59.85	58.25	57.02	50.06	43.89	36.94
Pennsylvania	63.09	65.34	66.27	61.17	57.23	53.29	52.28	43.44	39.92
Tennessee	43.01	42.23	38.28	35.99	35.91	34.72	33.44	28.27	22.44
West Virginia	47.11	48.81	46.94	45.94	43.56	42.37	39.55	36.71	30.88

Source: EIA Typical Electric Bills, January 1, 1988-1981

Table 2

TYPICAL MONTHLY ELECTRIC BILLS--NATIONWIDE AND TEN STATES WITH LARGEST EMISSION REDUCTIONS

(Residential 750 KWh--Dollars)

	1988	1987	1986	1985	1984	1983	1982	1981	1980
National Average	57.39	56.78	58.79	57.86	54.76	52.74	50.40	43.99	36.94
California	65.27	61.56	60.90	59.89	52.45	52.37	54.20	41.69	34.24
Illinois	50.89	54.65	57.90	55.01	53.83	50.82	45.86	39.89	33.51
Kentucky	39.81	42.31	42.44	42.14	40.34	38.14	36.54	32.00	27.71
Minnesota	47.80	44.71	48.17	46.65	43.19	43.65	42.67	38.04	33.78
Nebraska	43.15	43.40	44.11	44.34	40.26	39.64	35.04	33.59	29.51
New Mexico	60.16	63.06	62.73	59.38	51.88	54.33	56.42	49.68	43.25
North Carolina	56.69	57.95	56.15	52.64	50.76	47.22	43.98	37.70	32.63
South Dakota	48.71	49.71	50.64	50.36	47.29	46.38	45.50	37.61	33.32
Wisconsin	46.27	45.53	47.07	45.63	46.33	43.78	37.41	33.93	29.88
Wyoming	43.57	42.20	40.93	38.94	37.68	32.34	27.03	25.69	21.68

Source: EIA Typical Electric Bills, January 1, 1988-1981.

Table 9. Typical Monthly Electric Bills for Residential Service by State, 1988 and 1987

(Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1988	1987	1988	1987	1988	1987	1988	1987	1988	1987
Alabama	20.58	21.30	36.19	36.46	49.79	51.87	62.19	64.93	138.10	142.77
Alaska	23.85	24.53	42.43	43.78	60.37	62.40	78.84	81.27	188.34	194.21
Arizona	25.16	24.79	43.70	43.07	60.84	60.13	75.74	74.86	162.38	161.87
Arkansas	25.57	25.12	44.38	44.33	61.60	61.45	80.06	79.86	151.25	150.46
California	18.05	17.60	43.12	40.92	65.27	61.56	82.14	85.85	237.00	216.83
Colorado	20.52	19.91	36.41	35.24	52.28	50.55	68.15	65.85	163.30	157.86
Connecticut	29.03	27.85	49.50	48.72	68.57	67.39	90.42	88.84	199.60	195.26
Delaware	24.93	25.34	45.48	45.92	63.75	59.51	81.79	72.92	157.22	152.03
District of Columbia	12.02	13.56	25.97	29.24	37.85	42.45	52.90	59.50	131.91	148.41
Florida	23.65	22.76	41.53	39.69	59.41	56.61	78.86	74.88	184.35	184.86
Georgia	21.08	18.46	36.51	32.50	49.49	46.13	62.47	58.84	139.81	134.55
Hawaii	26.28	23.81	46.54	41.58	66.80	59.37	87.06	77.15	209.61	183.85
Idaho	11.46	11.12	22.34	21.65	33.40	32.38	44.61	43.25	113.24	109.83
Illinois	25.04	26.19	39.77	42.22	50.89	54.65	61.92	67.02	123.77	136.72
Indiana	25.48	25.20	43.59	43.52	58.49	58.84	73.41	74.21	142.88	147.03
Iowa	22.20	22.91	39.79	41.51	54.07	56.72	69.32	72.93	133.24	143.75
Kansas	22.97	23.25	40.40	41.17	56.09	57.33	72.81	74.52	165.20	169.34
Kentucky	16.20	17.12	29.19	30.85	39.81	42.31	51.29	53.37	115.71	123.97
Louisiana	18.06	17.61	33.72	32.81	49.07	47.70	63.76	62.05	149.28	145.64
Maine	18.92	18.76	39.17	38.67	61.45	61.02	83.73	83.19	217.40	216.14
Maryland	19.84	21.31	36.51	39.42	47.34	50.60	61.20	65.27	136.24	143.81
Massachusetts	25.16	24.33	44.67	42.90	62.74	59.40	82.28	77.49	193.49	179.76
Michigan	18.90	20.04	37.47	39.78	49.32	51.93	70.03	72.56	165.01	172.69
Minnesota	15.32	14.35	33.39	31.23	47.80	44.71	62.28	58.29	142.42	133.57
Mississippi	22.21	21.61	39.79	38.65	50.19	48.85	63.41	61.71	130.27	126.52
Missouri	22.04	21.80	38.54	38.03	52.39	51.73	67.45	66.55	129.44	126.73
Montana	16.71	16.00	30.53	29.49	44.24	43.02	57.86	56.55	139.73	137.75
Nebraska	18.99	19.13	32.08	32.29	43.15	43.40	53.63	53.91	101.64	102.21
Nevada	18.62	19.24	33.83	35.09	49.05	50.93	64.26	66.78	156.85	161.85
New Hampshire	23.73	23.96	50.15	50.74	68.14	68.66	94.46	95.37	225.08	226.80
New Jersey	26.48	29.52	49.72	52.93	69.75	72.54	90.20	94.81	185.65	194.99
New Mexico	22.60	23.49	42.24	44.10	60.16	63.06	78.76	82.78	190.93	195.23
New York	31.39	30.10	54.53	51.33	73.32	68.72	96.17	90.80	240.09	224.54
North Carolina	23.22	23.52	39.92	40.72	56.69	57.95	73.52	74.90	184.65	185.85
North Dakota	18.53	18.11	32.02	32.11	45.69	44.68	59.36	58.69	130.59	128.67
Ohio	22.75	23.07	43.06	43.63	61.09	61.80	78.23	79.15	153.03	151.62
Oklahoma	22.34	23.21	38.24	39.36	50.29	51.75	59.61	62.38	118.32	125.68
Oregon	14.70	12.96	25.54	24.15	36.67	35.74	47.80	47.32	114.51	116.83
Pennsylvania	27.40	28.00	49.16	50.29	63.09	65.34	83.05	87.44	162.93	171.12
Rhode Island	23.37	23.05	44.80	44.19	58.04	57.18	77.45	76.26	191.42	188.54
South Carolina	22.67	23.21	39.33	40.20	54.30	55.45	69.68	71.01	162.20	162.96
South Dakota	20.15	20.47	34.80	35.25	48.71	49.71	62.72	64.05	127.20	130.53
Tennessee	16.54	16.26	29.78	29.24	43.01	42.23	56.24	55.21	138.52	136.00
Texas	20.44	20.25	37.24	36.90	51.75	51.24	66.16	65.45	134.80	133.07
Utah	21.32	21.67	40.86	41.55	60.13	61.18	79.54	80.94	183.57	187.27
Vermont	17.13	17.75	45.75	47.14	64.60	64.60	94.06	95.82	265.52	276.57
Virginia	22.22	22.08	38.39	38.05	54.55	54.00	68.03	67.27	144.04	141.87
Washington	11.53	11.47	20.32	20.17	30.98	30.74	41.95	41.62	111.20	110.38
West Virginia	17.93	18.53	33.57	34.77	47.11	48.81	60.58	62.79	139.73	144.92
Wisconsin	18.66	18.85	33.94	34.33	46.27	46.53	61.54	62.31	152.83	154.80
Wyoming	18.16	17.52	31.08	30.08	43.57	42.20	55.92	54.31	119.57	125.39
U.S. Average	22.29	22.22	41.21	40.86	57.39	56.79	74.15	74.57	171.13	168.69

kWh = Kilowatthour.

Note: Data are averages, weighted by population, of typical net monthly bills based on the rate in effect on January 1 of the reporting year that is applicable to the majority of consumers either for the annual period or for the utility-specified winter period.

Source: Energy Information Administration, Form EIA-213, "Typical Net Monthly Bills."

Table 10. Rankings of Typical Monthly Electric Bills for Residential Service by State, 1988 and 1987

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1988	1987	1988	1987	1988	1987	1988	1987	1988	1987
Alabama	24	24	17	19	20	24	16	19	18	19
Alaska	40	42	36	41	37	44	38	42	40	43
Arizona	43	43	40	38	38	38	33	35	32	32
Arkansas	46	44	41	44	41	41	40	40	26	26
California	11	10	38	31	46	42	42	45	49	48
Colorado	23	20	19	17	25	18	26	22	34	30
Connecticut	50	48	48	47	49	48	48	47	45	46
Delaware	41	46	44	45	44	37	41	29	30	28
District of Columbia	3	4	4	4	4	7	5	12	13	25
Florida	38	30	34	27	34	29	36	33	44	40
Georgia	25	14	18	12	19	12	18	11	21	14
Hawaii	47	39	46	35	47	35	46	37	46	39
Idaho	1	1	2	2	2	2	2	2	3	2
Illinois	42	47	28	36	23	27	15	25	6	16
Indiana	45	45	39	39	33	34	31	31	23	24
Iowa	28	31	29	33	27	30	27	30	14	20
Kansas	35	36	32	32	30	32	30	32	37	36
Kentucky	6	8	5	8	5	6	4	4	5	5
Louisiana	12	11	13	13	17	14	21	14	25	23
Maine	18	16	26	24	40	39	45	44	47	47
Maryland	20	25	20	26	13	19	13	20	17	21
Massachusetts	44	41	42	37	42	36	43	38	43	38
Michigan	17	21	22	28	18	25	29	28	36	37
Minnesota	5	5	11	9	14	11	17	9	22	13
Mississippi	29	26	30	23	21	16	20	13	11	8
Missouri	27	28	25	21	28	22	24	23	10	9
Montana	8	6	7	6	9	8	9	8	20	17
Nebraska	19	18	9	11	7	9	6	5	1	1
Nevada	15	19	14	16	16	20	22	24	29	31
New Hampshire	39	40	50	49	48	49	50	50	48	50
New Jersey	48	50	49	51	50	51	47	49	38	44
New Mexico	32	37	35	42	36	45	37	43	41	45
New York	51	51	51	50	51	50	51	48	50	49
North Carolina	36	38	31	30	31	33	32	34	35	34
North Dakota	14	13	10	10	10	10	10	10	12	10
Ohio	34	33	37	40	39	43	34	39	28	27
Oklahoma	31	34	23	25	22	23	11	16	8	7
Oregon	4	3	3	3	3	3	3	3	4	4
Pennsylvania	49	49	47	48	43	47	44	46	33	35
Rhode Island	37	32	43	43	32	31	35	36	42	42
South Carolina	33	35	27	29	26	28	28	27	31	33
South Dakota	21	23	16	18	15	17	19	18	9	11
Tennessee	7	7	6	5	6	5	8	7	16	15
Texas	22	22	21	20	24	21	23	21	15	12
Utah	26	27	33	34	35	40	39	41	39	41
Vermont	9	12	45	46	45	46	49	51	51	51
Virginia	30	29	24	22	29	26	25	26	24	18
Washington	2	2	1	1	1	1	1	1	2	3
West Virginia	10	15	12	15	12	15	12	17	19	22
Wisconsin	16	17	15	14	11	13	14	15	27	29
Wyoming	13	9	8	7	8	4	7	6	7	6

kWh = Kilowatthour.

Note: Ranking of "1" represents lowest bill; ranking of "51" represents highest bill.

Source: Energy Information Administration, Form EIA-213, "Typical Net Monthly Bills."

Table 9. Weighted Average Typical Monthly Residential Bills by State, January 1, 1987, and January 1, 1986 (Dollars)

State	250 kWh		500 KWH		750 KWH		1,000 KWH		2,000 KWH	
	1987	1986	1987	1986	1987	1986	1987	1986	1987	1986
Alabama	21.25	21.17	36.39	36.23	51.76	51.26	64.85	64.04	142.88	140.38
Alaska	24.53	21.06	43.78	37.06	62.40	52.62	81.27	68.32	164.21	162.66
Arizona	24.79	26.05	43.07	43.96	60.13	60.43	74.96	74.28	161.87	154.96
Arkansas	25.12	23.23	44.33	39.96	61.45	55.25	79.96	71.50	160.46	138.32
California	17.80	18.06	40.92	40.77	61.56	60.90	85.86	86.22	218.83	217.07
Colorado	19.91	20.46	35.24	36.26	50.55	52.06	65.85	67.85	157.06	162.56
Connecticut	27.65	29.17	48.72	51.76	67.39	71.96	86.84	94.93	185.26	210.44
Delaware	25.34	26.82	45.92	48.88	59.51	66.18	72.92	87.33	152.03	201.79
District of Columbia	13.56	13.71	29.24	29.50	42.45	42.85	59.50	60.04	148.41	149.73
Florida	22.76	25.56	39.60	45.02	56.61	64.45	74.88	85.45	184.86	211.45
Georgia	18.46	18.42	32.50	32.45	46.13	46.07	59.84	59.78	134.55	134.44
Hawaii	23.81	29.99	41.59	53.96	59.37	77.93	77.15	101.90	183.85	245.72
Idaho	11.12	10.76	21.65	20.90	32.38	31.14	43.25	41.50	109.83	105.54
Illinois	26.14	27.09	42.17	44.56	54.60	57.90	66.97	71.21	136.65	142.06
Indiana	25.20	23.81	43.52	41.13	58.84	56.12	74.21	71.36	147.03	145.73
Iowa	22.91	22.95	41.51	41.67	56.72	56.49	72.93	72.96	143.75	144.02
Kansas	23.25	23.80	41.17	42.34	57.33	59.14	74.52	77.01	169.34	167.05
Kentucky	17.12	17.16	30.85	30.93	42.31	42.44	53.37	54.80	123.97	124.51
Louisiana	17.81	18.37	32.81	34.47	47.70	50.22	62.05	65.54	145.64	155.11
Maine	18.76	20.45	39.87	40.96	61.02	61.29	83.19	81.70	216.14	204.22
Maryland	21.31	22.00	39.42	40.82	50.80	52.86	65.27	69.05	143.81	150.80
Massachusetts	24.33	25.35	42.90	46.22	59.40	63.45	77.49	83.92	179.76	197.46
Michigan	20.04	20.59	39.76	40.85	51.93	53.56	72.56	74.76	172.69	178.30
Minnesota	14.35	15.55	31.22	33.49	44.71	48.17	58.29	62.96	133.55	142.85
Mississippi	21.81	21.66	36.65	36.81	48.85	48.99	61.71	61.91	126.52	127.29
Missouri	21.80	20.81	38.03	36.58	51.73	49.42	66.55	63.62	126.73	118.85
Montana	16.00	14.96	29.49	27.75	43.02	40.59	56.55	53.43	137.75	130.49
Nebraska	19.13	19.44	32.29	32.80	43.40	44.11	53.91	55.02	102.21	106.16
Nevada	19.24	20.11	35.09	36.82	50.93	53.53	66.78	70.24	161.85	170.51
New Hampshire	23.96	22.97	50.74	46.45	68.66	65.12	86.37	80.49	226.80	216.71
New Jersey	29.52	30.31	52.93	54.47	72.54	74.83	94.81	97.88	194.99	226.62
New Mexico	23.49	23.31	44.10	43.80	63.06	62.73	82.78	82.33	195.23	197.61
New York	30.10	33.49	51.33	61.17	68.72	78.55	90.80	105.24	224.54	258.58
North Carolina	23.58	22.88	40.86	39.49	58.17	56.15	75.25	72.53	166.36	161.81
North Dakota	18.11	18.40	32.11	32.70	44.68	45.56	58.69	59.85	128.67	131.60
Ohio	23.07	22.14	43.83	41.80	61.80	59.92	79.15	75.11	151.82	151.52
Oklahoma	23.21	22.76	39.35	39.36	51.74	52.39	62.38	63.71	125.67	131.00
Oregon	12.96	12.91	24.15	24.04	35.74	35.58	47.32	47.12	116.83	116.38
Pennsylvania	28.00	28.33	50.29	50.76	65.34	66.77	87.44	89.07	171.12	176.14
Rhode Island	23.05	24.99	44.19	48.06	57.18	62.46	76.26	83.51	186.54	205.61
South Carolina	23.21	23.09	40.20	39.93	56.45	55.24	71.01	70.72	162.96	162.12
South Dakota	20.47	20.78	35.25	35.86	48.71	50.64	64.05	65.31	130.53	133.72
Tennessee	16.26	14.80	29.24	26.54	42.23	38.28	55.21	50.02	136.00	123.67
Texas	20.25	21.64	36.90	39.78	51.24	55.56	65.45	71.12	133.07	149.40
Utah	21.67	21.09	41.55	40.69	61.18	60.30	80.94	79.89	187.27	185.36
Vermont	17.75	16.96	47.14	43.89	64.80	61.08	86.82	80.82	276.57	256.73
Virginia	22.08	22.50	38.05	38.77	54.00	55.02	67.27	68.31	141.87	142.75
Washington	11.47	11.30	20.17	19.84	30.74	30.41	41.62	41.29	110.38	109.87
West Virginia	18.53	17.88	34.77	33.51	48.81	46.94	62.79	60.30	144.82	138.78
Wisconsin	18.85	19.11	34.32	34.87	46.53	47.07	62.31	62.82	154.80	156.73
Wyoming	17.52	17.12	30.08	29.41	42.20	40.93	54.31	63.01	125.39	122.57
U.S. Average	22.22	22.87	40.60	42.84	56.78	59.79	74.57	77.80	168.69	177.21

Source: Energy Information Administration Form EIA-213, "Typical Net Monthly Bills."

Table 10. Rank of States By Weighted Average Typical Monthly Residential Bill, January 1, 1987, and January 1, 1986

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1987	1986	1987	1986	1987	1986	1987	1986	1987	1986
Alabama	24	26	19	17	24	19	19	18	19	17
Alaska	42	24	41	21	44	22	42	24	43	33
Arizona	43	44	36	40	39	37	34	33	32	27
Arkansas	44	37	44	27	41	36	40	30	35	15
California	10	12	31	30	42	38	45	43	48	47
Colorado	20	20	17	18	18	20	22	21	30	32
Connecticut	48	48	47	48	48	48	47	48	46	44
Delaware	46	45	45	46	37	47	29	44	28	41
District of Columbia	4	4	5	7	7	8	12	11	25	24
Florida	30	43	27	42	29	44	33	42	40	45
Georgia	14	15	12	9	12	11	11	9	14	14
Hawaii	39	49	35	49	35	50	37	50	39	49
Idaho	1	1	2	2	2	2	2	2	2	1
Illinois	47	46	36	41	27	33	25	28	18	18
Indiana	45	40	39	34	34	31	31	29	24	22
Iowa	31	34	33	35	30	29	30	32	20	21
Kansas	36	39	32	37	32	34	32	36	35	34
Kentucky	8	10	8	8	6	7	4	7	5	8
Louisiana	11	13	13	14	14	17	14	20	23	28
Maine	16	19	24	33	39	40	44	38	47	42
Maryland	25	29	26	31	19	23	20	22	21	25
Massachusetts	41	42	37	43	38	43	38	41	38	39
Michigan	21	21	28	32	25	25	28	34	37	37
Minnesota	5	7	9	12	11	14	9	15	13	20
Mississippi	26	28	23	23	16	15	13	13	8	9
Missouri	28	23	21	19	22	16	23	16	9	5
Montana	6	6	6	5	8	5	8	6	17	10
Nebraska	18	17	11	11	9	8	5	8	1	2
Nevada	19	18	16	20	20	24	24	25	31	35
New Hampshire	40	35	49	45	49	45	50	47	50	46
New Jersey	50	50	51	50	51	49	49	49	44	48
New Mexico	37	38	42	38	45	42	43	39	45	40
New York	51	51	50	51	50	51	48	51	49	51
North Carolina	38	33	30	25	33	32	35	31	34	30
North Dakota	13	14	10	10	10	10	10	10	10	12
Ohio	33	30	40	36	43	36	39	35	27	26
Oklahoma	34	32	25	24	23	21	16	17	7	11
Oregon	3	3	3	3	3	3	3	3	4	4
Pennsylvania	49	47	48	47	47	46	46	45	36	36
Rhode Island	32	41	43	44	31	41	36	40	42	43
South Carolina	35	36	29	28	28	27	27	26	33	31
South Dakota	23	22	18	16	17	18	18	19	11	13
Tennessee	7	5	4	4	5	4	7	4	15	7
Texas	22	27	20	26	21	30	21	27	12	23
Utah	27	25	34	29	40	38	41	37	41	38
Vermont	12	9	46	39	46	39	51	46	51	50
Virginia	29	31	22	22	26	26	26	23	16	19
Washington	2	2	1	1	1	1	1	1	3	3
West Virginia	15	11	15	13	15	12	17	12	22	16
Wisconsin	17	16	14	15	13	13	15	14	29	29
Wyoming	9	9	7	6	4	6	6	5	6	6

Note: Lowest bill has rank of "1"; highest bill has rank of "51".
Source: Energy Information Administration Form EIA-213, "Typical Net Monthly Bills."

Table 9. Weighted Average Typical Monthly Residential Bills by State, January 1, 1986, and January 1, 1985 (Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1986	1985	1986	1985	1986	1985	1986	1985	1986	1985
Alabama	21.17	21.01	36.23	35.96	51.26	50.94	64.04	63.65	140.38	139.64
Alaska	21.06	20.72	37.06	36.36	52.62	51.59	66.32	66.67	162.69	158.55
Arizona	26.05	25.63	43.96	42.99	60.43	58.62	74.28	72.40	154.96	151.15
Arkansas	23.23	20.83	39.86	35.23	55.25	48.54	71.50	62.51	138.32	117.75
California	18.08	17.74	40.77	40.09	60.90	59.80	86.22	84.64	217.07	211.77
Colorado	20.46	18.96	36.29	34.44	52.08	49.86	67.85	66.29	162.56	157.79
Connecticut	29.17	30.86	51.76	56.08	71.86	78.93	94.93	101.50	210.44	226.41
Delaware	26.82	27.53	48.68	50.24	66.18	70.05	87.33	90.84	201.79	208.05
District of Columbia	13.71	12.61	29.50	27.26	42.85	39.42	60.04	56.43	148.73	137.86
Florida	25.56	24.13	45.02	42.55	64.45	60.97	85.45	80.77	211.45	200.05
Georgia	18.42	18.18	32.45	31.87	46.07	45.38	58.78	57.91	134.44	132.44
Hawaii	29.99	32.01	53.96	57.99	77.83	83.97	101.90	109.95	245.72	265.82
Idaho	10.76	10.24	20.80	19.78	31.14	29.61	41.59	39.54	106.54	100.26
Illinois	27.09	24.90	44.56	42.12	57.80	56.01	71.21	69.00	142.08	138.75
Indiana	23.81	23.12	41.13	39.79	56.12	54.12	71.35	68.66	145.73	136.66
Iowa	22.95	22.36	41.67	40.69	56.49	54.03	72.86	71.00	144.02	140.31
Kansas	23.60	21.19	42.34	37.78	59.14	52.83	77.01	68.83	167.05	152.54
Kentucky	17.16	17.08	30.93	30.78	42.44	42.14	54.80	54.45	124.51	123.86
Louisiana	18.37	17.11	34.47	32.03	50.22	46.65	65.54	60.96	155.11	145.08
Maine	20.45	19.36	40.86	38.74	61.29	58.10	81.70	77.47	204.22	193.63
Maryland	22.00	21.34	40.82	39.48	52.66	51.16	66.05	65.31	150.60	143.40
Massachusetts	25.35	26.56	46.22	48.80	63.45	66.76	83.82	88.56	197.46	208.64
Michigan	20.59	17.78	40.85	35.24	53.58	48.83	74.76	70.84	178.30	172.15
Minnesota	15.55	15.10	33.49	32.42	48.17	46.65	62.96	61.04	142.85	136.28
Mississippi	21.86	18.85	36.81	33.54	48.99	42.68	61.91	54.22	127.29	112.38
Missouri	20.81	18.78	36.58	33.30	49.42	44.95	63.62	57.94	118.85	109.52
Montana	14.96	12.50	27.75	23.22	40.59	33.98	53.43	44.75	130.49	109.37
Nebraska	19.44	19.49	32.00	32.94	44.11	44.34	55.02	56.35	106.16	107.24
Nevada	20.11	19.18	36.82	34.94	53.53	50.71	70.24	66.48	170.51	161.05
New Hampshire	22.97	22.24	48.45	47.54	65.12	63.35	90.49	88.55	218.71	210.31
New Jersey	30.31	29.96	54.47	53.29	74.83	72.46	97.86	94.86	226.62	223.54
New Mexico	23.31	22.25	43.60	41.60	62.73	59.38	82.33	77.76	197.61	185.63
New York	33.49	34.97	61.17	64.14	78.55	82.99	105.24	111.14	258.58	274.52
North Carolina	22.86	21.47	39.49	37.02	56.15	52.64	72.53	67.90	161.81	150.57
North Dakota	18.40	18.66	32.70	33.23	45.56	46.41	59.85	60.97	131.60	134.26
Ohio	22.14	22.05	41.60	41.66	58.92	58.85	75.11	75.13	151.52	152.26
Oklahoma	22.76	19.69	39.36	34.29	52.39	46.75	63.71	58.49	131.00	128.38
Oregon	12.91	12.14	24.04	22.81	35.58	34.05	47.12	45.46	116.38	115.52
Pennsylvania	28.33	26.00	50.76	46.36	66.77	61.17	89.07	81.40	176.14	167.48
Rhode Island	24.99	25.14	48.06	48.44	62.46	62.74	83.51	83.86	205.61	208.61
South Carolina	23.09	21.83	39.93	37.65	55.24	52.09	70.72	66.66	162.12	152.96
South Dakota	20.79	20.68	35.86	35.67	50.64	50.36	65.31	64.94	133.72	132.64
Tennessee	14.80	13.96	26.54	24.96	36.26	35.99	50.02	46.96	123.67	116.20
Texas	21.64	23.22	36.78	40.47	55.56	55.10	71.12	69.56	149.40	151.10
Utah	21.09	20.78	40.69	40.90	60.30	60.84	79.80	80.97	185.36	171.19
Vermont	18.96	17.32	43.89	42.86	61.08	61.55	89.82	89.06	256.73	249.88
Virginia	22.50	21.54	38.77	37.44	55.02	53.34	68.31	66.58	142.75	141.16
Washington	11.30	11.22	19.84	19.19	30.41	29.24	41.28	39.56	109.87	106.04
West Virginia	17.88	17.36	33.51	32.73	48.94	45.94	60.30	59.08	138.78	136.15
Wisconsin	19.11	18.65	34.87	33.96	47.07	45.63	62.82	60.95	156.73	152.26
Wyoming	17.12	18.04	29.41	27.70	40.93	38.94	53.01	50.51	122.57	116.75
U.S. Average	22.07	22.61	43.64	41.96	58.79	57.96	77.80	76.37	177.21	175.99

Source: Energy Information Administration Form EIA-213, "Typical Net Monthly Bills."

Table 10. Rank of States By Weighted Average Typical Monthly Residential Bill, January 1, 1986, and January 1, 1985

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1986	1985	1986	1985	1986	1985	1986	1985	1986	1985
Alabama	26	29	17	24	19	24	18	20	17	21
Alaska	24	26	21	25	22	26	24	27	33	34
Arizona	44	44	40	42	37	36	33	35	27	28
Arkansas	37	28	27	21	28	19	30	19	15	10
California	12	13	30	33	38	39	43	43	47	46
Colorado	20	20	18	19	20	21	21	22	32	33
Connecticut	48	49	48	49	48	49	48	49	44	48
Delaware	45	47	46	47	47	47	44	47	41	43
District of Columbia	4	5	7	7	8	7	11	10	25	18
Florida	43	41	42	40	44	41	42	39	45	41
Georgia	15	15	9	9	11	12	9	11	14	13
Hawaii	49	50	49	50	50	51	50	50	49	50
Idaho	1	1	2	2	2	2	2	1	1	1
Illinois	46	42	41	39	33	33	28	29	18	19
Indiana	40	39	34	32	31	32	29	30	22	20
Iowa	34	38	35	35	29	31	32	34	21	22
Kansas	36	30	37	29	34	29	36	31	34	31
Kentucky	10	9	8	8	7	8	7	8	9	11
Louisiana	13	10	14	10	17	16	20	16	28	25
Maine	19	22	33	30	40	35	38	37	42	40
Maryland	29	31	31	31	23	25	22	23	25	24
Massachusetts	42	46	43	46	43	46	41	45	39	44
Michigan	21	14	32	22	25	20	33	33	37	38
Minnesota	7	7	12	11	14	17	15	18	20	17
Mississippi	28	19	23	16	15	9	13	7	8	6
Missouri	23	18	19	15	16	11	17	12	5	4
Montana	6	4	5	4	5	3	6	3	10	5
Nebraska	17	23	11	13	9	10	8	9	2	3
Nevada	18	21	20	20	24	23	25	24	35	35
New Hampshire	35	36	45	44	45	45	47	44	46	45
New Jersey	50	48	50	48	49	48	49	48	48	47
New Mexico	38	37	38	37	42	37	39	38	40	39
New York	51	51	51	51	51	50	51	51	51	51
North Carolina	33	32	25	26	32	28	31	28	30	26
North Dakota	14	17	10	14	10	15	10	17	12	15
Ohio	30	35	36	38	35	38	35	36	26	29
Oklahoma	32	24	24	18	21	18	17	13	11	12
Oregon	3	3	3	3	3	4	3	4	4	7
Pennsylvania	47	45	47	43	46	42	45	41	36	36
Rhode Island	41	43	44	45	41	44	40	42	43	42
South Carolina	39	34	28	28	27	27	26	26	31	32
South Dakota	22	25	16	23	18	22	19	21	13	14
Tennessee	5	6	4	5	4	5	4	5	7	8
Texas	27	40	26	34	30	34	27	32	23	27
Utah	25	27	29	36	36	40	37	40	38	37
Vermont	8	11	39	41	39	43	46	46	50	49
Virginia	31	33	22	27	26	30	23	25	19	23
Washington	2	2	1	1	1	1	1	2	3	2
West Virginia	11	12	13	12	12	14	12	14	16	16
Wisconsin	16	16	15	17	13	13	14	15	29	30
Wyoming	9	8	6	7	6	6	5	6	6	9

Note: Lowest bill has rank of "1"; highest bill has rank of "51".
Source: Energy Information Administration Form EIA-213, "Typical Net Monthly Bills."

Residential Service—Averages

Table 8A. State Average Typical Residential Bills, January 1, 1985, and January 1, 1984 (Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1985	1984	1985	1984	1985	1984	1985	1984	1985	1984
Alabama	21.01	20.64	35.98	36.21	50.94	49.75	63.65	62.06	139.64	135.61
Alaska	20.72	19.31	36.36	33.86	51.59	48.23	66.87	62.25	158.55	148.24
Arizona	25.63	24.36	42.89	40.65	58.92	56.62	72.40	68.29	151.15	142.22
Arkansas	20.63	20.49	35.23	34.73	48.54	42.45	62.51	56.29	117.75	111.46
California	17.74	16.05	40.08	38.74	58.80	52.45	84.84	74.43	211.77	187.04
Colorado	18.98	17.84	34.44	32.07	49.86	46.26	65.28	60.45	157.79	142.93
Connecticut	30.86	28.92	55.08	53.29	78.83	73.80	101.50	97.12	226.41	216.21
Delaware	27.53	26.17	50.24	50.91	70.05	71.03	89.84	91.21	208.06	211.74
District of Columbia	12.61	13.01	27.26	27.17	38.42	38.25	56.43	52.42	137.88	126.46
Florida	24.13	22.31	42.55	38.38	60.97	56.44	80.77	74.88	200.05	185.50
Georgia	18.18	17.91	31.97	31.44	45.36	44.58	57.91	56.86	132.44	129.83
Hawaii	32.01	32.56	57.89	58.19	83.97	85.80	109.95	112.40	265.82	272.06
Idaho	10.24	9.78	19.78	18.57	29.61	27.79	38.54	37.12	100.26	94.21
Illinois	24.90	23.09	42.12	43.84	55.01	53.83	68.00	72.46	136.75	130.01
Indiana	23.12	22.34	38.79	38.52	54.12	52.30	69.68	66.32	138.86	133.36
Iowa	22.36	22.25	40.89	40.84	54.03	54.58	71.00	71.84	140.31	143.78
Kansas	21.19	21.37	37.76	37.89	52.83	53.14	68.83	68.24	152.54	153.49
Kentucky	17.06	16.43	30.76	29.54	42.14	40.34	54.45	52.06	123.88	118.11
Louisiana	17.11	17.87	32.03	31.83	46.65	44.55	60.96	58.11	145.06	135.86
Maine	19.38	18.57	38.74	37.08	58.10	55.59	77.47	74.10	190.63	185.17
Maryland	21.34	20.51	39.48	38.10	51.16	49.47	65.31	63.31	143.40	139.61
Massachusetts	26.56	26.38	48.80	49.24	66.76	65.83	88.58	88.23	208.64	211.10
Michigan	17.78	15.61	35.24	30.89	48.83	42.67	70.84	62.52	172.15	148.43
Minnesota	15.10	13.94	32.42	30.11	46.65	43.19	61.04	56.46	136.28	125.07
Mississippi	18.85	19.65	33.54	35.06	42.68	44.94	54.22	57.23	112.38	119.64
Missouri	18.78	18.78	33.30	33.35	44.95	45.06	57.94	58.16	109.05	109.52
Montana	12.50	12.11	23.22	21.62	33.98	31.22	44.75	40.82	109.37	99.76
Nebraska	19.49	18.25	32.84	30.01	44.34	40.26	55.35	49.77	107.24	98.33
Nevada	19.18	18.70	34.94	33.98	50.71	49.26	66.48	64.54	161.05	156.21
New Hampshire	22.24	23.99	47.54	51.30	63.35	69.05	88.55	96.25	210.31	220.24
New Jersey	29.86	27.71	53.29	48.77	72.48	65.73	94.86	85.70	223.54	201.14
New Mexico	22.25	19.78	41.80	36.62	59.38	51.88	77.76	67.74	185.63	160.52
New York	34.97	34.00	64.14	62.40	82.99	80.64	111.14	108.04	274.52	267.80
North Carolina	21.47	20.59	37.02	35.88	52.64	50.76	67.89	65.32	150.57	143.19
North Dakota	18.86	17.96	33.23	31.80	46.41	44.47	60.97	58.40	134.26	126.05
Ohio	22.05	21.49	41.68	40.58	59.85	58.25	75.13	73.06	152.26	148.27
Oklahoma	19.69	18.04	34.29	31.04	46.75	42.10	58.49	52.46	128.38	114.12
Oregon	12.14	10.70	22.81	19.77	34.05	29.43	45.46	39.63	115.52	104.65
Pennsylvania	26.00	24.64	46.36	43.69	61.17	57.23	81.40	76.24	167.48	154.37
Rhode Island	25.14	25.77	48.44	49.71	62.74	64.50	83.06	86.11	206.61	211.51
South Carolina	21.83	19.95	37.85	33.93	52.09	46.69	66.96	59.47	152.86	134.82
South Dakota	20.68	19.76	36.67	33.85	50.36	47.29	64.94	60.84	132.64	124.64
Tennessee	13.98	13.97	24.96	24.95	35.99	35.91	46.98	46.88	116.20	115.88
Texas	23.22	22.18	40.47	38.58	55.10	53.47	69.56	69.48	151.10	147.75
Utah	20.78	18.54	40.90	38.31	60.84	52.73	80.97	68.96	171.19	156.46
Vermont	17.32	16.62	42.96	39.25	61.55	54.75	80.06	70.71	249.88	218.41
Virginia	21.54	21.59	37.44	37.66	53.34	53.73	68.58	67.19	141.16	143.19
Washington	11.22	10.41	19.19	17.73	28.24	26.75	38.58	35.91	106.04	93.80
West Virginia	17.36	16.51	32.73	31.02	45.94	43.98	59.06	56.02	136.15	130.80
Wisconsin	18.65	18.93	33.98	34.55	45.63	46.33	60.95	61.93	152.26	154.98
Wyoming	16.04	15.61	27.79	26.94	38.94	37.68	50.51	48.83	116.75	112.19
U.S. Average	22.61	21.57	41.86	40.18	57.86	54.76	76.37	72.77	175.99	166.00

Source: Energy Information Administration Form EIA-213, "Typical Net Monthly Bills."

Residential Service—Ranking

Table 8B. Rank of States from Low to High, January 1, 1985, and January 1, 1984

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1985	1984	1985	1984	1985	1984	1985	1984	1985	1984
Alabama	29	33	24	28	24	27	20	23	21	22
Alaska	26	24	25	19	26	24	27	24	34	30
Arizona	44	43	42	40	36	40	35	32	28	25
Arkansas	28	30	21	24	19	11	19	12	10	7
California	13	10	33	29	39	31	43	40	46	42
Colorado	20	14	19	17	21	20	22	20	33	26
Connecticut	49	49	48	49	49	49	49	49	48	47
Delaware	47	48	47	47	47	48	47	47	43	46
District of Columbia	5	5	6	7	7	7	10	9	18	15
Florida	41	39	40	38	41	41	39	41	41	41
Georgia	15	16	9	14	12	17	11	14	13	17
Hawaii	50	50	50	50	51	51	50	51	50	51
Idaho	1	1	2	2	2	2	1	2	1	2
Illinois	42	41	38	43	33	36	29	37	19	18
Indiana	39	40	32	35	32	30	30	29	20	20
Iowa	38	38	35	41	31	37	34	36	22	29
Kansas	30	34	29	32	29	33	31	33	31	34
Kentucky	9	11	8	8	8	9	8	8	11	11
Louisiana	10	15	10	15	16	16	16	16	25	23
Maine	22	20	30	30	35	39	37	39	40	41
Maryland	31	31	31	33	25	26	23	26	24	24
Massachusetts	46	46	46	45	46	46	45	46	44	44
Michigan	14	9	22	11	20	12	33	25	38	33
Minnesota	7	6	11	10	17	13	18	13	17	14
Mississippi	19	26	16	25	9	18	7	15	6	12
Missouri	18	22	15	18	11	19	12	17	4	6
Montana	4	4	4	4	3	4	3	4	5	4
Nebraska	23	19	13	9	10	8	9	7	3	3
Nevada	21	21	20	22	23	25	24	27	35	37
New Hampshire	36	42	44	48	45	47	44	48	45	48
New Jersey	48	47	49	44	48	45	48	44	47	43
New Mexico	37	28	37	26	37	29	38	31	39	39
New York	51	51	51	51	50	50	51	50	51	50
North Carolina	32	32	26	27	28	28	28	28	26	28
North Dakota	17	17	14	16	15	15	17	18	15	16
Ohio	35	35	39	39	38	43	36	38	29	32
Oklahoma	24	18	18	13	18	10	13	10	12	9
Oregon	3	3	3	3	4	3	4	3	7	5
Pennsylvania	45	44	43	42	42	42	41	42	36	35
Rhode Island	43	45	45	46	44	44	42	45	42	45
South Carolina	34	29	28	21	27	22	26	19	32	21
South Dakota	25	27	23	20	22	23	21	21	14	13
Tennessee	6	7	5	5	5	5	5	5	8	10
Texas	40	37	34	36	34	34	32	34	27	31
Utah	27	25	36	34	40	32	40	35	37	38
Vermont	11	13	41	37	43	38	46	43	49	49
Virginia	33	36	27	31	30	35	25	30	23	27
Washington	2	2	1	1	1	1	2	1	2	1
West Virginia	12	12	12	12	14	14	14	11	16	19
Wisconsin	16	23	17	23	13	21	15	22	30	36
Wyoming	8	8	7	6	6	6	6	6	9	8

Source: Energy Information Administration Form EIA-213, "Typical Net Monthly Bills."

Residential Service—Averages

Table 8A. State Average Typical Residential Bills, January 1, 1984 and January 1, 1983 (Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1984	1983	1984	1983	1984	1983	1984	1983	1984	1983
Alabama	20.84	19.95	35.21	33.97	48.75	46.22	62.05	60.25	125.81	131.89
Alaska	19.31	17.95	33.66	30.81	48.23	44.11	62.25	56.67	148.24	132.48
Arizona	24.36	23.20	40.65	38.38	56.62	50.84	68.28	63.55	142.22	130.65
Arkansas	20.49	19.61	34.73	33.22	42.45	41.40	56.29	54.68	111.46	105.64
California	16.05	16.23	30.74	30.65	52.45	52.37	74.43	72.82	187.04	183.42
Colorado	17.84	18.41	32.07	33.31	46.26	48.15	60.45	63.00	142.93	148.58
Connecticut	29.92	27.55	53.29	48.60	73.80	67.32	97.12	88.30	216.21	196.10
Delaware	28.17	26.10	50.91	46.96	71.03	65.22	91.21	83.53	211.74	192.68
District of Columbia	13.01	13.46	27.17	28.04	38.25	39.65	52.42	54.23	126.46	131.15
Florida	22.31	20.79	39.38	36.43	56.44	51.96	74.88	69.08	185.50	171.10
Georgia	17.91	16.86	31.44	29.96	44.58	41.06	56.66	52.55	129.83	120.83
Hawaii	32.58	29.15	60.19	53.14	85.80	77.06	112.40	100.90	272.06	244.25
Idaho	9.78	9.41	18.57	17.83	27.79	26.68	37.12	35.63	94.21	90.48
Illinois	23.09	21.87	43.84	41.94	53.63	50.82	72.46	68.44	130.01	120.29
Indiana	22.34	20.10	38.52	34.96	52.30	47.35	68.32	60.06	133.36	129.80
Iowa	22.25	18.98	40.84	34.55	54.58	45.72	71.84	59.96	143.76	118.81
Kansas	21.37	19.67	37.98	35.05	53.14	48.82	69.24	63.73	153.49	140.18
Kentucky	16.43	15.46	29.54	27.76	40.34	38.14	52.06	49.16	118.11	110.63
Louisiana	17.87	17.91	31.83	31.86	44.55	44.34	58.11	57.73	135.86	135.37
Maine	18.57	17.51	37.09	34.95	55.59	52.37	74.10	69.81	185.17	174.29
Maryland	20.51	20.43	38.10	37.86	49.47	49.09	63.31	62.80	139.61	138.71
Massachusetts	26.39	24.34	49.24	44.38	65.83	60.31	88.23	80.03	211.10	189.21
Michigan	15.61	15.76	30.89	31.23	42.67	43.44	62.52	62.78	148.43	148.82
Minnesota	13.94	14.09	30.11	30.41	43.19	43.65	56.46	57.06	125.07	126.54
Mississippi	19.65	19.16	35.06	34.39	44.94	45.09	57.23	57.57	119.64	119.96
Missouri	18.76	18.09	33.35	32.29	45.08	43.39	58.16	56.00	109.52	105.08
Montana	12.11	11.85	21.62	21.38	31.22	30.80	40.82	40.42	96.76	96.73
Nebraska	18.25	17.93	30.01	29.78	40.26	39.64	49.77	49.71	98.33	98.47
Nevada	18.70	18.93	33.98	34.52	49.26	50.06	64.54	65.61	156.21	158.90
New Hampshire	23.99	22.66	51.30	46.92	69.05	62.01	86.25	84.25	229.24	203.22
New Jersey	27.71	28.51	48.77	50.37	65.73	68.25	85.70	89.06	201.14	209.60
New Mexico	19.78	20.46	36.62	38.18	51.86	54.33	67.74	71.29	160.52	170.36
New York	34.00	32.36	62.40	58.11	80.64	75.89	108.04	106.89	267.80	266.57
North Carolina	20.59	19.18	35.88	33.52	50.76	47.22	65.32	60.95	143.19	133.91
North Dakota	17.96	17.66	31.90	31.25	44.47	43.71	58.40	57.28	128.05	125.22
Ohio	21.49	21.19	40.58	39.52	58.25	57.02	73.06	71.90	148.27	148.14
Oklahoma	18.04	18.17	31.04	31.36	42.10	42.49	52.46	52.99	114.12	115.78
Oregon	10.70	9.84	19.77	17.53	29.43	25.73	39.63	34.71	104.65	94.48
Pennsylvania	24.64	23.03	43.69	40.91	57.23	53.29	76.24	71.05	154.37	148.40
Rhode Island	25.77	23.57	49.71	41.00	64.50	58.71	86.11	79.47	211.51	180.00
South Carolina	19.95	20.41	33.93	35.00	46.89	48.54	59.47	61.99	134.82	140.05
South Dakota	19.76	19.25	33.85	33.19	47.29	46.39	60.84	59.69	124.64	121.82
Tennessee	13.87	12.59	24.85	22.94	35.91	34.72	46.88	46.49	115.88	117.15
Texas	22.18	20.58	38.58	35.98	53.47	49.36	69.48	64.24	147.75	135.96
Utah	19.54	18.80	39.31	36.27	52.73	49.53	69.96	65.79	156.46	144.69
Vermont	18.62	18.47	39.25	38.90	54.75	50.39	78.71	73.40	218.41	205.86
Virginia	21.58	21.11	37.86	36.71	53.73	52.32	67.19	65.43	143.19	139.76
Washington	10.41	9.32	17.73	15.44	26.75	23.21	35.81	31.07	83.80	80.85
West Virginia	16.51	17.22	31.02	30.22	43.56	42.37	56.02	54.44	130.90	124.86
Wisconsin	18.93	18.13	34.55	33.09	46.33	43.76	61.93	56.98	154.98	147.27
Wyoming	16.61	13.30	26.84	23.12	37.66	32.34	48.63	42.00	112.19	96.31
U.S. Average	21.57	20.73	40.19	38.36	54.76	52.74	72.77	69.96	166.00	160.22

Source: Energy Information Administration Form EIA-213.

Residential Service—Ranking

Table 8B. Rank of States from Low to High, January 1, 1984 and January 1, 1983

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,000 kWh	
	1984	1983	1984	1983	1984	1983	1984	1983	1984	1983
Alabama	33	32	26	24	27	27	23	24	22	20
Alaska	24	19	19	13	24	19	24	15	30	24
Arizona	43	44	40	39	40	38	32	30	25	21
Arkansas	30	30	24	21	11	11	12	13	7	8
California	10	11	29	35	31	39	40	42	42	42
Colorado	14	23	17	22	20	25	20	29	26	36
Connecticut	49	48	49	48	49	48	49	48	47	48
Delaware	48	47	47	47	46	47	47	46	46	45
District of Columbia	5	6	7	6	7	9	9	13	15	22
Florida	39	38	38	34	41	37	41	37	41	40
Georgia	16	13	14	9	17	10	14	8	17	15
Hawaii	50	50	50	50	51	50	51	50	51	50
Idaho	1	2	2	3	2	3	2	2	2	2
Illinois	41	41	43	44	36	36	37	36	18	14
Indiana	40	33	35	29	30	26	29	33	20	20
Iowa	38	26	41	27	37	22	36	22	29	12
Kansas	34	31	32	31	33	29	33	31	34	31
Kentucky	11	9	8	7	9	7	8	7	11	9
Louisiana	15	17	15	17	18	20	16	19	23	26
Maine	20	15	30	26	39	40	38	38	40	41
Maryland	31	35	33	37	36	30	26	28	24	28
Massachusetts	46	46	45	45	48	45	46	45	44	43
Michigan	9	10	11	14	12	15	25	27	30	38
Minnesota	6	8	10	12	13	16	13	16	14	19
Mississippi	26	27	25	25	16	21	15	18	12	13
Missouri	22	20	18	18	19	14	17	14	8	7
Montana	4	4	4	4	4	4	4	4	4	6
Nebraska	19	18	9	10	8	8	7	6	3	5
Nevada	21	25	22	36	25	33	27	34	37	38
New Hampshire	42	42	48	46	47	46	48	47	49	47
New Jersey	47	49	44	49	45	49	44	49	43	49
New Mexico	28	36	28	36	29	42	31	40	39	39
New York	51	51	51	51	50	51	50	51	50	51
North Carolina	32	28	27	23	28	24	28	25	28	25
North Dakota	17	16	16	15	15	17	18	17	16	18
Ohio	35	40	39	41	43	43	38	41	32	34
Oklahoma	18	22	13	16	10	13	10	10	9	10
Oregon	3	3	3	2	3	2	3	2	5	3
Pennsylvania	44	43	42	42	42	41	42	39	35	37
Rhode Island	45	45	46	43	44	44	45	44	45	44
South Carolina	29	34	21	30	22	28	19	28	21	30
South Dakota	27	29	20	20	23	23	21	21	13	16
Tennessee	7	5	5	5	5	6	5	9	10	11
Texas	37	37	36	32	34	31	34	32	31	27
Utah	25	24	34	33	32	32	35	35	38	32
Vermont	13	12	37	40	38	34	43	43	48	48
Virginia	36	39	31	38	35	38	30	33	27	29
Washington	2	1	1	1	1	1	1	1	1	1
West Virginia	12	14	12	11	14	12	11	12	19	17
Wisconsin	23	21	23	19	21	18	22	20	36	30
Wyoming	8	7	6	6	6	5	6	5	6	4

Source: Energy Information Administration Form EIA-213.

Residential Service—Averages

Table 8A. State Average Typical Residential Bills, January 1, 1983 and January 1, 1982 (Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1983	1982[1]	1983	1982[1]	1983	1982[1]	1983	1982[1]	1983	1982[1]
Alabama	18.95	18.02	33.97	29.52	48.22	41.23	60.25	53.93	131.89	118.06
Alaska	17.95	17.43	30.91	29.70	44.11	41.22	56.67	52.99	132.48	123.54
Arizona	23.20	25.90	36.38	39.86	50.94	52.44	63.55	65.63	130.65	135.14
Arkansas	18.61	18.16	33.22	30.13	41.40	37.24	54.68	47.88	105.64	94.93
California	18.23	17.45	36.65	38.53	52.37	54.43	72.82	74.56	183.42	207.26
Colorado	18.41	17.04	33.31	30.86	48.15	44.25	63.00	58.02	148.58	139.90
Connecticut	27.55	27.88	48.90	48.84	67.32	66.11	88.30	86.99	196.10	208.12
Delaware	26.10	28.65	46.96	48.14	65.22	67.07	83.53	86.05	182.89	189.42
District of Columbia	13.46	14.06	28.04	27.79	39.65	36.69	54.23	50.42	131.15	117.56
Florida	20.78	20.62	36.43	36.40	51.66	52.17	68.06	68.29	171.10	172.09
Georgia	16.06	15.98	28.96	27.74	41.06	38.97	52.55	50.10	120.63	116.08
Hawaii	29.15	33.71	53.14	62.26	77.05	90.73	100.90	119.13	244.25	289.85
Idaho	9.41	6.88	17.63	13.16	26.08	20.20	35.63	27.70	90.48	80.05
Illinois	21.97	19.15	41.94	37.24	50.82	45.84	66.44	61.81	120.29	114.14
Indiana	20.10	18.12	34.96	31.36	47.35	42.72	60.06	54.40	129.80	117.21
Iowa	18.98	19.73	34.55	35.71	45.72	45.57	59.96	59.96	119.81	124.13
Kansas	19.67	18.19	35.05	32.23	48.92	44.66	63.73	57.99	140.18	127.87
Kentucky	15.46	14.87	27.76	26.58	38.14	36.36	49.16	46.79	110.63	105.20
Louisiana	17.91	15.73	31.86	28.22	44.34	38.82	57.73	50.72	135.37	117.90
Maine	17.51	17.31	34.95	33.71	52.37	49.76	69.81	65.81	174.29	162.04
Maryland	20.43	18.61	37.86	35.38	49.09	46.22	62.80	58.87	138.71	129.74
Massachusetts	24.34	23.76	44.38	43.69	60.31	57.33	80.03	75.79	189.21	178.52
Michigan	15.78	14.10	31.23	27.90	43.44	38.42	62.78	56.08	148.82	132.96
Minnesota	14.09	16.16	30.41	29.57	43.65	42.54	57.06	55.62	126.54	117.27
Mississippi	18.16	17.67	34.38	31.54	45.09	40.96	57.57	52.13	119.96	117.84
Missouri	18.09	16.96	32.28	30.22	43.39	40.60	56.00	52.37	105.08	98.29
Montana	11.85	9.84	21.38	17.69	30.90	25.61	40.42	33.53	98.73	81.96
Nebraska	17.83	16.05	29.78	26.43	39.64	35.27	49.71	44.30	96.47	87.01
Nevada	18.93	15.41	34.52	28.48	50.06	41.55	65.61	54.62	158.90	133.06
New Hampshire	22.66	23.15	46.92	41.72	62.0[illegible]	58.22	84.25	74.74	203.22	183.09
New Jersey	29.51	27.31	50.37	47.53	68.25	64.00	89.08	83.19	209.60	194.26
New Mexico	20.46	21.01	38.18	39.30	54.33	56.47	71.29	74.36	170.36	178.19
New York	32.36	31.27	58.11	58.41	79.69	76.63	106.89	102.86	266.57	256.67
North Carolina	19.18	18.04	33.52	31.56	47.22	44.05	60.95	56.67	133.91	124.42
North Dakota	17.66	16.53	31.25	29.29	43.71	40.93	57.28	53.68	125.22	124.40
Ohio	21.19	19.27	39.52	34.93	57.02	50.06	71.90	63.03	148.14	130.47
Oklahoma	18.17	15.52	31.36	27.48	42.49	38.75	52.99	45.67	115.78	98.80
Oregon	9.84	8.91	17.53	15.66	25.73	22.60	34.71	30.83	94.48	83.62
Pennsylvania	23.03	21.26	40.91	39.05	53.29	52.28	71.05	70.00	149.40	148.15
Rhode Island	23.57	21.82	41.00	37.76	59.71	54.96	79.47	73.10	190.00	174.36
South Carolina	20.41	19.19	35.00	32.58	48.54	44.98	61.99	57.25	140.06	128.96
South Dakota	19.25	18.57	33.19	32.11	46.38	44.59	59.69	57.42	121.82	116.39
Tennessee	12.59	12.19	22.94	22.12	34.72	33.44	46.49	44.76	117.15	112.68
Texas	20.59	18.76	35.66	32.90	49.36	44.44	64.24	58.36	135.96	124.26
Utah	18.80	21.43	36.27	38.63	48.53	44.98	65.79	60.74	144.69	121.80
Vermont	16.47	15.32	38.90	35.82	50.39	46.63	73.40	67.74	205.86	189.38
Virginia	21.11	20.30	36.71	35.07	52.32	49.85	65.43	62.14	139.76	131.63
Washington	9.32	7.40	15.44	12.00	23.21	17.70	31.07	23.50	80.65	60.24
West Virginia	17.22	16.23	30.22	26.31	42.37	38.55	54.44	50.72	124.96	115.82
Wisconsin	16.13	15.92	33.09	29.81	43.76	37.33	58.68	50.18	147.27	126.28
Wyoming	13.50	10.90	23.12	19.23	32.34	27.32	42.00	35.64	96.31	86.46
United States	20.72	19.83	38.35	36.96	52.74	50.07	69.96	66.39	160.22	11[illegible].89

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[1] Revised figures based on 1980 census population.
Source: Energy Information Administration Form 213.

Residential Service—Ranking

Table 8B. Rank of States from Low to High, January 1, 1983 and January 1, 1982

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1983	1982[1]	1983	1982[1]	1983	1982[1]	1983	1982[1]	1983	1982[1]
Alabama	32	18	24	18	27	21	24	20	23	21
Alaska	19	24	13	20	19	20	15	18	24	23
Arizona	44	46	36	44	36	41	30	37	21	36
Arkansas	30	33	21	21	11	11	13	10	8	7
California	11	25	35	43	39	42	42	44	42	46
Colorado	23	22	22	23	28	28	29	29	35	37
Connecticut	48	49	46	49	48	48	48	49	46	48
Delaware	47	47	47	48	47	49	46	48	45	47
District of Columbia	6	7	8	11	9	9	13	13	22	18
Florida	38	39	34	37	37	39	37	40	40	40
Georgia	13	15	9	10	10	15	9	11	15	14
Hawaii	50	51	50	51	50	51	50	51	50	51
Idaho	2	1	3	2	3	2	3	2	2	2
Illinois	41	32	44	30	35	33	36	34	14	12
Indiana	33	28	29	24	25	24	23	21	20	16
Iowa	26	36	27	35	22	32	22	32	12	24
Kansas	31	29	31	26	29	29	31	26	31	29
Kentucky	9	9	7	8	7	8	7	9	9	10
Louisiana	17	13	17	13	20	14	19	14	26	20
Maine	15	23	28	31	40	36	38	38	41	39
Maryland	35	37	37	34	30	34	28	31	28	31
Massachusetts	46	45	45	46	45	46	45	46	43	43
Michigan	10	8	14	12	15	13	27	24	36	34
Minnesota	8	18	12	19	16	23	16	23	19	17
Mississippi	27	26	25	25	21	19	18	16	13	19
Missouri	20	21	18	22	14	17	14	17	7	8
Montana	4	4	4	4	4	4	4	4	6	3
Nebraska	18	17	10	7	8	7	8	6	5	6
Nevada	25	11	26	15	33	22	34	22	38	35
New Hampshire	42	44	48	45	46	44	47	45	47	44
New Jersey	49	48	49	47	49	47	49	47	49	49
New Mexico	36	40	38	42	42	45	40	43	39	42
New York	51	50	51	50	51	50	51	50	51	50
North Carolina	28	27	23	26	24	25	25	25	25	27
North Dakota	16	20	15	18	17	18	17	19	18	26
Ohio	40	35	41	32	43	38	41	36	34	32
Oklahoma	22	12	16	9	13	10	10	8	10	9
Oregon	3	3	2	3	2	3	2	3	3	4
Pennsylvania	43	41	42	41	41	40	39	41	37	38
Rhode Island	45	43	43	40	44	43	44	42	44	41
South Carolina	34	34	30	29	28	30	26	28	30	30
South Dakota	29	30	20	27	23	28	21	27	16	15
Tennessee	5	6	5	6	6	6	6	7	11	11
Texas	37	31	32	30	31	27	32	30	27	25
Utah	24	42	33	38	32	31	35	33	32	22
Vermont	12	10	40	36	34	35	43	39	48	45
Virginia	39	38	36	33	38	37	33	35	29	33
Washington	1	2	1	1	1	1	1	1	1	1
West Virginia	14	19	11	14	12	18	12	15	17	13
Wisconsin	21	14	19	17	18	12	20	12	33	28
Wyoming	7	5	6	5	5	5	5	5	4	5

[1] Revised figures.
Source: Energy Information Administration Form 213.

Residential Service—Averages

Table 8A. State Average Typical Residential Bills, January 1, 1982 and January 1, 1981 (Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1982	1981	1982	1981	1982	1981	1982	1981	1982	1981
Alabama	16.01	16.30	28.50	28.38	41.22	40.60	53.82	53.00	118.09	114.05
Alaska	17.51	16.30	29.76	27.60	41.44	38.56	53.26	49.53	124.10	115.34
Arizona	23.89	20.12	39.47	32.69	52.24	43.12	65.49	54.42	134.72	110.52
Arkansas	19.24	17.82	30.25	28.34	37.36	35.70	48.06	45.96	95.39	86.13
California	17.38	13.74	39.31	29.75	54.20	41.68	74.20	57.61	206.36	152.42
Colorado	17.22	13.97	31.17	25.95	44.62	37.47	58.53	49.42	141.33	108.35
Connecticut	27.58	22.98	48.86	41.11	66.03	55.81	86.93	73.68	208.00	180.92
Delaware	26.76	24.05	48.36	43.21	67.42	55.90	86.54	68.69	200.83	144.51
District of Columbia	14.06	14.12	27.79	26.95	36.69	36.50	50.42	48.34	117.56	118.55
Florida	20.60	17.17	36.36	31.02	52.15	44.85	69.21	58.29	171.60	145.35
Georgia	15.97	13.99	27.72	23.73	38.97	33.06	50.10	42.34	116.06	97.29
Hawaii	33.71	27.87	62.27	49.29	90.76	70.77	119.19	92.60	290.07	223.67
Idaho	6.88	10.36	13.07	16.28	20.05	22.38	27.46	28.54	79.10	66.34
Illinois	19.18	17.06	37.30	33.06	45.86	39.89	61.98	53.94	114.17	100.77
Indiana	18.02	16.25	31.29	28.06	42.66	37.19	54.35	47.43	117.29	101.36
Iowa	19.77	17.13	35.77	31.10	45.61	39.42	60.05	51.91	124.37	104.20
Kansas	18.17	15.84	32.17	27.81	44.62	38.17	57.92	49.44	127.48	108.48
Kentucky	14.83	13.18	26.57	23.43	36.54	32.00	46.80	40.80	104.51	91.58
Louisiana	15.74	13.71	28.35	24.93	39.01	33.02	51.08	43.48	118.60	98.70
Maine	17.31	19.77	33.70	34.07	49.75	47.92	65.80	61.76	161.97	144.57
Maryland	19.80	18.19	35.37	32.21	46.21	41.57	58.82	52.62	129.56	144.22
Massachusetts	23.76	24.54	43.73	45.48	57.40	59.24	75.88	78.34	178.38	187.56
Michigan	14.11	16.25	27.93	30.19	38.43	40.09	56.18	54.79	133.12	130.71
Minnesota	16.19	12.47	29.65	26.50	42.67	38.04	55.78	49.59	117.59	97.98
Mississippi	17.50	17.50	31.22	31.25	40.78	40.80	51.99	52.02	118.00	118.45
Missouri	16.70	15.38	29.81	27.40	40.14	36.88	51.89	47.70	97.26	91.82
Montana	9.85	10.24	17.78	17.57	25.78	24.90	33.78	32.23	82.76	76.20
Nebraska	15.97	15.36	26.24	25.17	35.04	33.59	44.01	42.22	86.79	83.81
Nevada	15.51	14.66	28.68	27.02	41.84	39.36	55.00	51.71	133.98	125.80
New Hampshire	23.20	24.72	41.78	44.65	56.36	59.84	74.90	79.72	183.37	186.66
New Jersey	27.29	25.58	47.46	43.07	64.05	58.54	83.20	75.75	194.44	175.24
New Mexico	21.08	19.01	39.36	34.97	56.42	49.68	74.25	63.96	177.21	146.34
New York	31.26	26.62	58.39	49.37	76.54	65.79	102.77	87.47	257.36	218.18
North Carolina	17.99	15.58	31.50	27.11	43.98	37.70	56.61	48.39	124.31	105.35
North Dakota	16.45	13.56	29.09	23.36	40.42	32.23	53.04	41.09	122.94	95.06
Ohio	19.28	17.48	34.99	30.71	50.13	43.89	63.21	56.16	130.93	117.78
Oklahoma	15.52	14.17	27.48	25.29	36.74	33.84	45.64	42.23	98.68	92.13
Oregon	8.88	11.07	15.86	18.99	22.91	26.90	30.86	34.81	83.94	82.36
Pennsylvania	21.32	18.01	39.17	33.34	52.39	43.44	70.16	58.59	148.28	125.02
Rhode Island	21.87	25.02	37.97	48.31	55.15	63.92	73.40	85.09	174.76	208.88
South Carolina	19.28	15.41	32.71	26.05	45.19	35.87	57.49	45.99	129.45	107.74
South Dakota	18.90	16.34	32.76	27.31	45.50	37.61	58.60	48.40	118.20	96.18
Tennessee	12.19	10.49	22.13	18.69	33.45	28.27	44.77	37.85	112.70	95.34
Texas	18.79	16.45	32.95	28.46	44.52	37.80	58.46	49.50	123.53	102.11
Utah	21.50	18.75	36.95	32.16	45.09	38.95	60.94	52.24	121.78	105.91
Vermont	15.26	15.32	35.48	29.95	46.64	37.87	67.51	52.43	188.03	132.32
Virginia	20.32	18.32	35.14	31.65	49.98	44.09	62.26	55.95	131.75	117.78
Washington	7.07	6.19	11.54	10.01	17.21	14.81	22.99	19.60	59.51	49.31
West Virginia	16.21	15.33	28.27	26.39	39.48	36.71	50.62	46.93	115.52	106.48
Wisconsin	15.97	13.64	28.90	24.71	37.41	33.93	50.30	44.93	126.65	110.83
Wyoming	10.82	10.18	19.03	18.14	27.03	25.69	35.23	33.60	86.13	77.19
United States	20.02	17.76	37.26	32.81	50.40	43.99	66.84	58.16	156.12	133.90

Residential Service—Ranking

Table 8B. **Rank of States from Low to High, January 1, 1982 and January 1, 1981**

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1982	1981	1982	1981	1982	1981	1982	1981	1982	1981
Alabama	17	27	15	27	20	33	20	33	19	29
Alaska	26	27	20	24	21	27	19	25	25	31
Arizona	45	43	44	39	40	37	37	35	36	27
Arkansas	33	36	22	16	11	14	10	14	7	7
California	24	12	42	29	42	36	43	39	48	44
Colorado	22	13	23	14	27	20	29	22	37	25
Connecticut	49	44	49	44	48	44	49	45	49	46
Delaware	47	45	48	46	49	45	48	44	47	40
District of Columbia	7	15	11	19	9	16	13	21	16	35
Florida	39	33	37	33	39	41	40	41	40	42
Georgia	14	14	10	9	14	10	11	11	14	14
Hawaii	51	51	51	50	51	51	51	51	51	51
Idaho	1	4	2	2	2	2	2	2	2	2
Illinois	32	31	39	40	33	31	34	34	12	17
Indiana	28	25	25	26	23	19	21	17	15	18
Iowa	36	32	36	34	32	30	32	38	27	20
Kansas	29	24	27	25	28	26	27	23	29	26
Kentucky	9	8	8	8	8	7	9	7	10	8
Louisiana	13	11	14	11	15	9	15	12	21	16
Maine	23	42	31	42	36	42	38	42	39	41
Maryland	37	38	34	38	34	35	31	32	31	30
Massachusetts	46	46	46	48	46	47	46	47	43	48
Michigan	8	25	12	31	13	32	24	36	34	38
Minnesota	18	7	19	18	24	25	23	26	17	15
Mississippi	25	35	24	35	19	34	17	29	18	34
Missouri	21	21	21	23	17	18	16	18	8	9
Montana	4	3	4	3	4	3	4	3	3	3
Nebraska	15	20	7	12	7	11	8	9	6	6
Nevada	11	17	16	20	22	29	22	27	35	37
New Hampshire	44	47	45	47	44	48	45	48	44	47
New Jersey	48	49	47	45	47	46	47	46	46	45
New Mexico	40	41	43	43	45	43	44	43	42	43
New York	50	50	50	51	50	50	50	50	50	50
North Carolina	27	23	26	21	25	22	25	19	26	21
North Dakota	20	9	18	7	18	8	18	5	23	11
Ohio	34	34	32	32	38	39	36	38	32	32
Oklahoma	12	16	9	13	10	12	8	10	9	10
Oregon	3	6	3	6	3	5	3	5	4	5
Pennsylvania	41	37	41	41	41	38	41	40	38	36
Rhode Island	43	48	40	49	43	49	42	49	41	49
South Carolina	35	22	28	15	30	15	26	15	30	24
South Dakota	31	29	29	22	31	21	30	20	20	13
Tennessee	6	5	6	5	6	6	7	6	11	12
Texas	30	30	30	28	26	23	28	24	24	19
Utah	42	40	38	37	29	28	33	30	22	22
Vermont	10	18	35	30	35	24	39	31	45	39
Virginia	38	39	33	36	37	40	35	37	33	33
Washington	2	1	1	1	1	1	1	1	1	1
West Virginia	19	19	13	17	16	17	14	16	13	23
Wisconsin	16	10	17	10	12	13	12	13	28	28
Wyoming	5	2	5	4	5	4	5	4	5	4

Source: Energy Information Administration Form 213.

Table 7A. State Average Typical Residential Bills, January 1, 1981 and January 1, 1980 (Dollars)

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1981	1980	1981	1980	1981	1980	1981	1980	1981	1980
United States	17.76	16.29[1]	32.61	27.80[1]	43.99	36.94[1]	58.16	48.79[1]	133.90	110.91[1]
Alabama	16.30	13.53	28.38	23.63	40.69	33.99	53.00	44.34	114.05	94.11
Alaska	16.30	14.44	27.80	24.20	38.56	33.51	49.53	42.78	115.34	99.29
Arizona	20.12	18.03	32.69	31.02	43.12	40.95	54.42	51.64	110.52	104.79
Arkansas	17.82	13.96	26.34	22.61	35.70	28.58	45.96	37.00	86.13	73.10
California	13.74	11.59	29.75	25.07[1]	41.69	34.24	57.61	47.65	152.42	123.72
Colorado	13.97	12.35	25.95	22.65	37.47	32.96	49.42	43.27	108.35	93.09
Connecticut	22.97	19.75	41.11	33.93	55.81	44.78	73.68	57.95	180.92	139.14
Delaware	24.05	21.98	43.21	37.76	55.90	49.14	68.69	63.23	144.51	138.26
District of Columbia	14.12	11.01	26.95	20.09	36.50	27.31	49.34	36.39	118.55	87.04
Florida	17.17	14.37	31.02	25.53	44.85	36.68	59.29	48.37	145.34	117.89
Georgia	13.99	12.95	23.73	21.70	33.06	30.08	42.34	38.42	97.29	87.01
Hawaii	27.87	21.96	49.29	37.65	70.77	53.52	92.60	69.60	223.67	166.49
Idaho	10.36	8.83	16.28	13.65	22.38	18.46	28.54	23.28	66.34	52.70
Illinois	17.06	14.50	33.06	27.55	39.89	33.51	53.94	44.94	100.77	86.22
Indiana	16.25	15.50	28.06	26.68	37.19	35.22	47.43	44.83	101.36	88.44
Iowa	17.13	15.70	31.10	28.80	39.42	36.80	51.91	48.44	104.20	98.72
Kansas	15.84	14.42	27.81	25.21	36.17	34.43	49.44	44.58	108.48	97.28
Kentucky	13.18	11.64	23.43	20.34	32.00	27.71	40.80	35.27	91.58	78.95
Louisiana	13.71	11.63	24.93	20.32	33.02	26.47	43.48	35.04	98.70	77.49
Maine	19.77	15.69	34.07	26.05	47.92	35.98	61.76	45.91	144.57	105.16
Maryland	18.19	16.23	32.21	28.57	41.57	36.62	52.62	46.44	114.22	100.87
Massachusetts	24.54	18.81	45.48	34.41	59.24	44.30	78.34	58.69	187.56	130.72
Michigan	16.25	14.16	30.19	25.65	40.09	33.74	54.79	45.85	130.71	114.37
Minnesota	12.47	11.17	26.50	23.57	38.04	33.78	49.59	43.97	97.98	86.42
Mississippi	17.50	14.15	31.25	25.02	40.80	32.72	52.02	42.20	118.45	98.90
Missouri	15.38	14.98	27.40	27.01	36.88	33.69	47.70	44.45	91.82	95.28
Montana	10.24	8.77	17.57	14.99	24.90	21.20	32.23	27.41	76.20	64.71
Nebraska	15.36	13.73	25.17	22.46	33.59	29.51	42.22	37.26	83.81	73.59
Nevada	14.66	14.38	27.02	25.31	39.36	35.97	51.71	48.64	125.80	110.61
New Hampshire	24.72	19.60	44.65	34.41	59.84	44.69	79.72	59.02	186.66	133.82
New Jersey	25.58	20.71	43.07	35.12	58.54	46.61	75.75	60.02	175.24	136.90
New Mexico	19.01	16.88	34.97	30.85	49.68	43.25	63.96	55.71	146.34	129.75
New York	26.62	21.88[1]	49.37	40.12[1]	65.79	51.99[1]	87.47	69.57[1]	218.18	170.61[1]
North Carolina	15.58	13.76	27.11	24.05	37.70	32.63	48.39	41.83	105.35	90.41
North Dakota	13.56	13.31	23.36	22.94	32.23	31.48	41.99	40.67	95.06	90.91
Ohio	17.48	16.20	30.71	28.26	43.89	39.94	56.16	51.11	117.78	108.64
Oklahoma	14.17	12.76	25.29	22.51	33.84	29.69	42.23	36.72	82.13	78.56
Oregon	11.07	9.55	18.99	16.01	26.90	22.47	34.81	28.92	82.36	67.69
Pennsylvania	18.01	17.12	33.34	31.56	43.44	39.92	58.59	53.89	125.02	114.61
Rhode Island	25.02	19.32	48.31	35.42	63.92	44.36	85.09	58.57	208.88	141.23
South Carolina	15.41	15.21	26.05	25.40	35.87	34.77	45.89	44.38	107.74	102.57
South Dakota	16.34	14.89	27.31	24.92	37.61	33.32	48.40	42.85	96.18	89.06
Tennessee	10.49	8.52	18.69	14.80	26.27	22.44	37.85	30.16	95.34	76.45
Texas	16.45	14.72	28.46	25.28	37.80	33.93	49.50	43.87	102.11	90.39
Utah	18.75	16.59	32.16	27.86	38.95	31.51	52.24	42.78	105.91	86.32
Vermont	15.32	13.90	29.95	27.10	37.87	33.64	52.43	46.80	132.32	118.31
Virginia	18.32	19.01	31.65	33.10	44.09	46.31	55.95	58.92	117.78	125.40
Washington	6.19	6.04	10.01	9.40	14.81	12.91	19.80	18.44	49.31	39.73
West Virginia	15.33	13.13[1]	26.39	22.49[1]	36.71	30.88[1]	46.93	39.58[1]	106.48	88.50[1]
Wisconsin	13.64	11.98	24.71	21.71	33.93	29.88	44.93	39.42	110.83	94.75
Wyoming	10.18	8.70	18.14	15.43	25.69	21.68	33.60	28.32	77.18	64.83

[1] Revised figures.

Source: Energy Information Administration Form 213.

Residential Service—Ranking

Table 7B. Rank of States from Low to High, January 1, 1981 and January 1, 1980

State	250 kWh		500 kWh		750 kWh		1,000 kWh		2,500 kWh	
	1981	1980	1981	1980	1981	1980	1981	1980	1981	1980
Alabama	27	18	27	20	33	29	33	25	29	24
Alaska	27	28	24	22	27	22	25	20	31	30
Arizona	43	44	39	41	37	41	35	40	27	33
Arkansas	36	22	16	15	14	10	14	11	7	6
California	12	9	29	16	36	30	39	36	44	41
Colorado	13	13	14	17	20	20	22	22	25	23
Connecticut	44	47	44	44	44	46	45	43	46	48
Delaware	45	51	46	50	45	49	44	49	40	47
District of Columbia	15	7	19	7	16	8	21	8	35	16
Florida	33	25	33	29	41	37	41	37	42	39
Georgia	14	15	9	10	10	14	11	13	14	15
Hawaii	51	50	50	49	51	51	51	51	51	50
Idaho	4	5	2	2	2	2	2	2	2	2
Illinois	31	29	40	35	31	22	34	30	17	12
Indiana	25	34	26	32	19	33	17	29	18	18
Iowa	32	36	34	39	30	38	28	38	20	28
Kansas	24	27	25	25	26	31	23	28	26	27
Kentucky	8	11	6	9	7	6	7	8	8	11
Louisiana	11	10	11	8	9	7	12	7	16	9
Maine	42	35	42	31	42	35	42	32	41	34
Maryland	38	38	38	38	35	36	32	33	30	31
Massachusetts	46	42	48	45	47	43	47	45	48	44
Michigan	25	24	31	30	32	26	36	31	36	37
Minnesota	7	6	18	19	25	27	26	24	15	14
Mississippi	35	23	35	24	34	19	29	18	34	29
Missouri	21	32	23	33	18	25	18	27	9	26
Montana	3	4	3	4	3	3	3	3	3	3
Nebraska	20	19	12	13	11	11	9	12	6	7
Nevada	17	26	20	27	29	34	27	34	37	36
New Hampshire	47	46	47	45	48	45	48	47	47	45
New Jersey	49	48	45	47	46	48	46	48	45	46
New Mexico	41	40	43	40	43	42	43	42	43	43
New York	50	49	51	51	50	50	50	50	50	51
North Carolina	23	20	21	21	22	18	19	17	21	21
North Dakota	9	17	7	18	8	16	8	16	11	22
Ohio	34	37	32	37	39	40	38	30	32	35
Oklahoma	16	14	13	14	12	12	10	10	10	10
Oregon	6	6	6	6	5	6	5	5	5	5
Pennsylvania	37	41	41	42	36	39	40	41	36	38
Rhode Island	48	45	49	48	49	44	49	44	49	49
South Carolina	22	33	15	28	15	32	15	26	24	32
South Dakota	29	30	22	23	21	21	20	21	13	19
Tennessee	5	2	5	3	6	5	6	6	12	8
Texas	30	31	26	26	23	28	24	23	19	20
Utah	40	39	37	36	28	17	30	19	22	13
Vermont	18	21	30	34	24	24	31	35	39	40
Virginia	39	43	36	43	40	47	37	46	33	42
Washington	1	1	1	1	1	1	1	1	1	1
West Virginia	19	18	17	12	17	15	16	14	23	17
Wisconsin	10	12	10	11	13	13	13	15	28	25
Wyoming	2	3	4	5	4	4	4	4	4	4

Source: Energy Information Administration Form 213.

QUESTIONS FROM SENATOR JOHNSTON

Question 16: What is the effect of the Lieberman amendment, as adopted by the Senate Committee on Environment and Public Works on November 16, 1989, on the DOE uranium enrichment program and on other DOE facilities? Please include a discussion of feasibility and an estimate of additional operating costs, where possible. For the enrichment program, include a per SWU estimate of any price increase that might result from enactment of S. 1630, as ordered reported by the Senate Environment Committee.

Answer: The Lieberman amendment to the Clean Air Act proposals affects federally owned or leased facilities. At federally owned facilities that operate in the service territory of a utility that must comply with the provisions of the Clean Air Act amendments, these facilities must install by September 30, 1995, all electric energy conservation improvements that are cost-effective based upon a life-cycle cost analysis. In addition, these same federal facilities by January 1, 1995, must utilize renewable and alternative clean energy technologies to satisfy at least 10 percent of the total electric needs of that facility. After January 1, 1995, newly constructed federal facilities must comply with both of these mandates. The amendment also applies to federally leased facilities where the lease exceeds 35,000 square feet and where the federally leased space exceeds 70 percent of the leasable space and the building is located in a service area of a utility that must comply with the provisions of the Clean Air Act amendments. After

Answer 16
(Continued)

January 1, 1992, no federal agency shall enter into or renew a lease in new or renovated buildings unless the building has installed all electric energy conservation improvements that are cost-effective based upon a life-cycle cost analysis. The EPA has some discretion to limit the applicability of these provisions where the federal facility uses less than 1,000 megawatt hours per year.

Report language indicates that federal facilities must implement site specific renewable and alternative clean energy technologies. The report interpretation of this requirement states that each federal facility within the affected utility service area does not have to meet the 10-percent power requirement, but that the combination of all the federal facilities within the utility's service area must meet the 10-percent requirement. Whether each federal facility or the combined federal facilities within each affected utility's area must meet the renewable and alternative clean energy technologies requirement makes little difference from the perspective of the cost burden imposed. While the Department recognizes the need for leadership in the renewable and alternative clean energy technologies area, it is unrealistic to impose this cost burden upon all federal facilities within each affected utility's service area. The cost of electricity

Answer 16
(Continued)

from these technologies could be in the range several multiples of the current cost of electricity. While the federal government may be willing to utilize some renewable and alternative clean energy technologies at some federal facilities in order to demonstrate their technological feasibility, a universal requirement would cost more than any benefits that could be derived from this program.

A broader interpretation of the Lieberman amendment could require federal facilities to purchase power from nonfossil sources. This interpretation poses serious problems for affected federal facilities. If it could be implemented, the requirement would shift nonfossil power from existing customers to federal facilities and fossil capacity previously used by federal facilities to nonfederal facilities. Little would be gained from this reshuffling of power usage. Moreover, federal facilities purchase power from a power grid. It is difficult, if not impossible, to determine where the power originated.

The implementation of this amendment will cause an undue burden on all of DOE facilities that are located within the utility service areas of affected utilities. The Department operates a wide range of facilities ranging

Answer 16 (Continued)

from office buildings to energy-intensive operations such as uranium enrichment facilities.

The Department's gaseous diffusion plants (GDP) at Portsmouth, Ohio, and Paducah, Kentucky, utilize up to 2,000 and 3,000 megawatts (MW) of electric power, respectively, to enrich uranium. Section 415(a)(2) of the Lieberman amendment would require the purchase of up to 200 MW at the Portsmouth GDP and up to 300 MW at the Paducah GDP from renewable and alternative clean energy technologies.

The amendment would require, therefore, that up to 500 MW of electric power would have to be purchased from nonfossil fuel sources, i.e., nuclear, solar, geothermal, wind, etc. Of these sources, nuclear power represents the lowest cost option, and is the only nonfossil fuel source in the regions surrounding DOE's plants that could provide power in the amount (500 MW) required. It is questionable whether DOE could gain assured access to nuclear generation for the quantities of power required without signing long-term contracts. However, the cost of nuclear generated power on a long-term contract basis is estimated to be more costly than the power that is currently being purchased by DOE from dedicated coal-fired stations under a long-term contract. These stations were originally built exclusively to service DOE's

Answer 16
(Continued)

plants over 30 years ago, they are almost fully amortized and therefore the cost of electricity from these plants is quite attractive. As a result, the cost to purchase up to 500 MW of nuclear power is projected to be as much as $100 to $200 million per year higher than power purchased from the dedicated coal-fired stations.

The higher cost for power associated with the Lieberman amendment is expected to increase the cost of production for DOE's plants by about $10 per SWU. The net effect would be negative in terms of eroding DOE's ability to sell uranium enrichment services in the highly competitive international marketplace. We believe this is counterproductive in terms of reducing DOE's ability to optimize the return on investment to taxpayers from a successful uranium enrichment enterprise in the U.S. and continue the economical supply of enriched uranium fuel for nuclear plants that are free of emissions that have possible acid rain or global climate change effects.

QUESTIONS RELATED TO
AIR TOXICS PROVISIONS
OF S. 1630 AND
POTENTIAL EFFECTS
ON THE OIL AND GAS
AND ELECTRIC UTILITY INDUSTRIES

Oil and Gas Industry Issues

Question: What effect will compliance with the hazardous air pollutant and ozone nonattainment titles of S. 1630 and S. 1490 have on the producing sector of the domestic oil and gas industry?

Answer: We are currently evaluating industry information responsive to these questions. The following data are taken from estimates by the Independent Petroleum Association of America (IPAA) and the American Petroleum Institute (API) and from the January 18 report by the Business Roundtable.

To what extent will compliance with these provisions force producers to shut in stripper wells and other marginal production?

Impacts may be greatest on small producers such as stripper wells, which are defined as wells producing 10 barrels per day or less. In 1988, there were an estimated 612,000 producing wells in the United States, of which 454,000 (74 percent) were stripper wells. These stripper wells produced 442 million barrels of oil, representing 14.9 percent of the total U.S. oil production.

IPAA estimates that, under both S.1490 and S.1630, 125,000 stripper wells would close and that over 4,000 new wells would not be drilled. API estimates that 175,000 stripper wells, each producing two barrels or less per day, would close. IPAA also estimates that 29,000 of the wells would be permanently plugged.

The actual impacts of the bills are uncertain. The designation of emission source categories, the technology based standards and the added regulation due to residual risk requirements are undefined. If a standard such as that in S. 1630 of risk reduction to below one in ten-thousand, with a goal of one in one million, was imposed on stripper wells, the impacts would be greatest. For this reason, S. 1490, which allows the EPA Administrator flexibility in:

- defining emission source categories,
- determining whether to require control technology standards for smaller emission source categories, and

- determining what is continuing unreasonable risk after technology standards are in place,

is the more appropriate regulatory program.

How much domestic production might be lost as a result of such shutins?

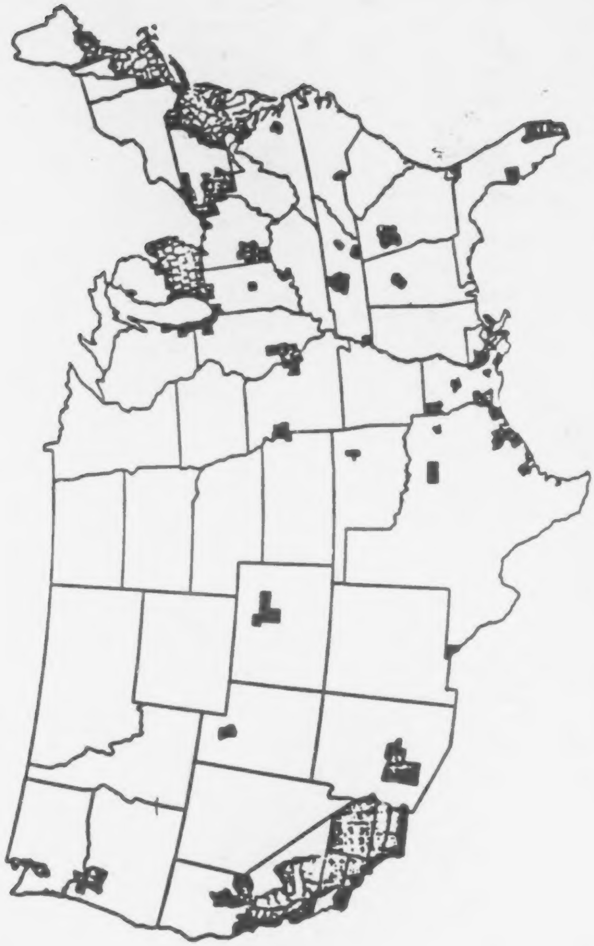
The average productivity of producing oil wells in the United States in 1988 was about 13.3 barrels per day. The stripper wells averaged 2.7 barrels per day. The 1988 stripper well production estimate of 442 million barrels represents approximately 14.9 percent of the total U.S. production.

The impact would be felt first by the smallest producers. A significant percentage of stripper wells could be forced out of production, many of them permanently. The production lost from stripper wells will likely be made up by increased imports of crude oil.

If the IPAA and API estimates for expected closings of stripper wells occur, approximately 25 percent, principally the smaller wells would be closed, which could be up to 3 percent of total U.S. crude oil production.

Are there any particular States or producing regions where the effect of compliance with these provisions will be particularly severe?

Currently, stripper wells are located in 28 States, with the majority (greater than 50 percent) in five States: California, Louisiana, Ohio, Oklahoma, and Texas. Many regions within these States have been designated as ozone nonattainment areas. The attached map of the United States shows which U.S. counties were in nonattainment at the beginning of 1988, based on data compiled by the Argonne National Laboratories. For these five states, counties in ozone nonattainment are listed in the attached table.



National O_3 Nonattainment Counties as of December 31, 1987

TABLE

Counties in Ozone Nonattainment in the States of California, Louisiana, Ohio, Oklahoma and Texas as of 1/1/88

California	Louisiana (Parishes)	Ohio	Oklahoma	Texas
Almeda	Ascension	Astabula	Tulsa	Brazoria
Butte	Beauregard	Butler		Dallas
Contra Costa	Bossier	Clark		El Paso
El Dorado	Caddo	Clermont		Galveston
Fresno	Calcasieu	Clinton		Gregg
Imperial	East Baton Rouge	Columbiana		Harris
Kern	Grant	Cuyahoga		Jefferson
Kings	Iberville	Geauga		Orange
Los Angeles	Jefferson	Greene		Tarrant
Madera	Lafayette	Hamilton		Victoria
Marin	Lafourche	Jefferson		
Merced	Orleans	Lake		
Monterey	Pointe Coupee	Lucas		
Napa	St. Bernard	Mahoning		
Orange	St. Charles	Miami		
Placer	St. James	Montgomery		
Riverside	St. John The Baptist	Portage		
Sacremento	St. Mary	Richland		
San Benito	West Baton Rouge	Stark		
San Bernardino		Summit		
San Diego		Trumbull		
San Francisco		Warren		
San Joaquin				
San Mateo				
Santa Barbara				
Santa Clara				
Santa Cruz				
Solano				
Sonoma				
Stanislaus				
Sutter				
Tulare				
Ventura				
Yuba				

Source: Argonne National Laboratories

Question: **How will costs imposed as a consequence of compliance with the hazardous air pollutant and ozone nonattainment titles of S. 1630 and S. 1490 affect the price of oil, natural gas and by products derived from oil and natural gas paid by consumers?**

Answer: In general, compliance costs would be passed through to consumers of petroleum products and natural gas in the form of higher prices. The rise in petroleum product prices could be dampened somewhat by competition from crude oil and product imports, depending on market conditions.

The actual impact of the proposed hazardous air pollutant and ozone nonattainment titles of S. 1630 and S. 1490 on consumer prices for petroleum products would depend on the actual investment and operations costs required by the industry to comply with the new emission standards. The range of these costs is quite speculative at this time since the specifics of added regulations and operating permits are not known. However, the recent Business Roundtable report (January 18, 1990) cites API as estimating that total annual costs for air toxics legislation for the petroleum industry could range from $3.2 billion to

$12.8 billion. The attached table, from the Business Roundtable report, shows how these estimated costs are distributed (Case II subtotals are incremental costs above Case I). The production subsector for both cases represents over 50 percent of the total estimated costs while the cost to the refinery sector would be about 11 (Case I) to 21 percent of the total petroleum sector costs.

The bills would have additional costs associated with the ozone nonattainment provisions. While these costs are not estimated, review of the ozone nonattainment counties map provided for a prior question, shows that many areas in ozone nonattainment contain petroleum production and refining facilities. The example, 109 of 188 US refineries (58%) were in ozone nonattainment counties in 1987. These facilities are likely to be required to reduce their VOC and NOx emissions. (Some of the controls required in such areas may be similar to controls needed for the air toxic provisions).

API Total Annualized Costs
($ Millions)

Case I

Sector	O&M	Capital Recovery	Total
Production	550	1,220	1,770
Marketing	300	600	900
Transportation	65	140	200
Refining	175	180	350
Sub Totals	1,100	2,100	3,200

Case II

Sector	O&M	Capital Recovery	Total
Production	810	4,450	5,260
Marketing	400	1,100	1,500
Transportation	120	350	470
Refining	340	2,000	2,340
Sub Totals	1,700	7,900	9,600
Totals	2,800	10,000	12,800

Figure 11

Question: **What effect will compliance with the hazardous air pollutant and ozone nonattainment titles of S. 1630 and S. 1490 have on the refining and processing sector of the domestic oil and gas industry?**

Answer: Both S. 1630 and S. 1490 direct EPA to promulgate a standard for each source category of emissions, which would require the installation of maximum achievable control technology (MACT) for each major source in the category. The impact of the hazardous air pollutant provisions of S. 1630 and S. 1490 on the petroleum refining industry would vary greatly according to the definition of the MACT for each emissions source.

The extent to which compliance costs would cause domestic refiners to reduce or terminate operations in the United States would vary according to the size and profit margin of each refinery. Small, simple refineries with no specialty products or market niche, which account for about 2 percent of U.S. refining capacity, would be the most adversely affected and the most likely to close.

Refinery capacity in the United States is heavily concentrated in the Gulf Coast region. Refinery output from this region supplements refinery output in the Eastern two-thirds of the Nation. Gulf Coast refineries tend to have narrower profit margins than refineries outside the region; therefore, these refineries would be most at risk from the legislation.

The alternative fuels provisions of S. 1490 will also have an economic impact on refiners. If large quantities of alternative fuels displace petroleum-based fuels, the impact will be reduced demand for current petroleum products. This may be offset to some degree since petroleum refiners will likely play a role in providing clean alternative fuels. However, in order to do this, additional capital equipment costs will likely be required to produce these new clean fuels.

Costs that may be incurred due to these provisions include:

Ozone Nonattainment Areas

- Source emission fees and program administration fees set at $75 and $15 per emitted ton of VOC and NOx.

- Fees set at $5000/ton if the refinery is in an area which does not attain compliance on the prescribed schedule (fee is not for all tons emitted but is set for exceedences above a percentage of baseline, nor are fees set for all categories of nonattainment areas).

- Costs associated with required technology standards for major sources.

Air Toxic Provisions (MACT)

- Annual costs estimated by API range from $350 million to $2.7 billion.

Electric Utility Issues

Question 1: **What effect will compliance with the provisions regulating emissions of hazardous air pollutants have on electric utilities?**

Please compare the effect of Title III of S. 1630 as ordered reported by the Committee on Environment and Public Works on November 16, 1989, with that of title III of S. 1490.

Answer: Title III of S. 1630 would require that regulations be set for 100 percent of source categories that contribute to the listed species of air toxic pollutants. For many of these pollutants, electric utilities would be required to add to their present controls and to controls required under the Acid Rain Title, additional controls that would representing Maximum Achievable Control Technologies (MACT). The air toxics pollutants would include both emitted particulate and emitted gases.

Particulates would in all probability have to be controlled by high efficiency fabric filter baghouses or more costly controls. EEI has estimated costs for universal use of baghouses to be about $11 billion annually; for some units these technologies may already be in place. Toxic gas species would require other controls; for example, one estimate to control chlorine suggests that the flue stream would have to be scrubbed (not necessarily the same scrubbers as may be used for desulfurization) at a potential cost of $7 billion.

An additional cost to power units is that the inflexibility of the S. 1630 toxic provisions may compromise the flexibility now afforded affected units to be controlled as part of the Acid Rain Title in thier choice of SO_2 and NO_x emission controls.

We do not now know how much present controls and the added controls of the proposed Acid Rain Title would reduce utility air toxic emissions. There is also lack of data on the level of risk caused by toxic emissions from controlled power plants. For these reasons, S. 1490 does not propose that MACT provisions be set for electric utilities before such information is developed. Instead, S. 1490 calls for a study of the toxic emissions and the potential risk due to electric utility emissions. This study would develop special regulations for air toxic streams from power plants if added controls are determined as needed. Thus, the added controls determined to be needed would be tailored in a similar manner to the process that was required by 1980 amendments to the Resource Conservation and Recovery Act, to manage hazardous waste streams from coal-fired electric utility units. The reduction in costs using the S. 1490 process compared to S. 1630 is likely to be billions of dollars annually.

Question: What will be the effect of such compliance costs on electric utility ratepayers?

Answer: Based on a review of the distribution of power plants and populations, it would appear that the greater burden of control costs will be borne by consumers east of the Mississippi River; consumers in the Northeastern States would be the most seriously affected. Costs are likely to rise as the industry invests significant monies into the control of air pollutants.

If the added annual costs for MACT approaches the levels suggested in the previous answer--on the order of $20 billion for S. 1630, the cost impacts to ratepayers will be much higher than, for example, the costs of the proposed acid rain controls. On the other hand, if the study provisions of S. 1490 are used, costs would be incurred only as needed to protect human health and the environment. The flexibility developed in specially tailored programs would likely result in significant cost reduction.

Question: How will such compliance costs for utilities compare with those imposed as a consequence of other titles of S. 1630 and S. 1490?

Answer: Comparative data is provided in the previous answer. Generally, in S. 1630 the MACT power plant costs may be much larger than costs of other titles of S. 1630. Also S. 1490 costs would be much lower than S. 1630 and would be better justified by determination of actual levels of risk and risk reduction.

Question: How will MACT affect electric utilities' choice of electric generation technology and fuel?

Answer: It is clear that coal-fired power plants will be classified as a major source category. Most plants would be required to install MACT if S. 1630 provisions are enacted. Installing MACT will be costly; controls are required without any demonstration that such controls produce significant reduction in public health risks. Potential new construction could be cancelled and existing facilities could be shut down.

There are many references that report emissions of trace elements from coal-burning plants. Under the MACT standards, coal-fired electricity will become more costly, forcing utilities to accommodate alternative fuels or technologies. The added costs and required equipment due to the air toxics provisions could jeopardize the Clean Coal Program.

Because MACT standards would be no less stringent than the most stringent emissions level that is achieved in practice by a source in the same category or subcategory, differences in scale, process, operations, location, and other factors could make it impossible for some facilities to satisfy this requirement.

Question: What are the energy policy implications of such choices?

Answer: If S. 1630 air toxic provisions are enacted, the requirements are likely to severely constrain use of coal for generation of electricity supplied by coal-fired units. There may be substantial demand for greater use of natural gas, escalating fuel costs for both electricity supply and for direct heating uses. Electricity demand may not be adequately met since alternative technologies may not be sufficiently developed or accepted. Demands for supply by non-fossil fuel technologies would increase. If oil-fired units are used more intensively, oil imports would rise.

Thus, it is important that the consequences of these provisions be studied in terms of our overall National Energy Strategy prior to imposition of MACT. Such a study would be a natural corollary to the present electric utility study of air toxics proposed in S. 1490.

EPA

ANSWERS TO QUESTIONS OF SENATOR JOHNSTON FOR HEARING ON THE ENERGY AND POLICY IMPLICATION OF S.1630 COMMITTEE ON ENERGY AND NATURAL RESOURCES

Question 1

Concisely assess the benefits that would result from the passage of the acid rain provisions of S. 1630. Where monetary estimates are not available, please provide any other quantitative estimates of costs and benefits (e.g., lives saved or lakes preserved). Where quantitative estimates are not available, please provide qualitative descriptions of benefits. In all cases, please provide an assessment of the certainty one can attach to the benefits. Summarize your assessment in one or more tables showing the type, the nature, and the certainty of each benefit. Include these types at a minimum: lakes and streams, forests, crops, materials, visibility, and health.

For each type of benefit above, cite the major studies or research underlying the benefit assessment and describe the extent to which NAPAP findings support or fail to support your assessment of benefits from S. 1630.

Answer 1

The specific benefits that will be achieved as a result of the President's acid rain proposal relate to: (1) improvements in surface water chemistry leading to improvements in surface water biology, and in other cases the prevention of some acidification associated with a low probability of the presence of fish in streams and lakes; (2) increased visibility as a function of decreased levels of sulfates in the atmosphere; (3) reduced stress on high elevation spruce forests as a function of increasing the pH of mountain clouds -- the increase in pH will be caused by a decrease of the level of sulfates in the atmosphere; and, (4) decreased amount of materials damage caused by current levels of acidic and acid forming compounds in the atmosphere; and, (5) a possible reduction of public health risk through a reduction in the formation and concentration of sulfate-based acid aerosols that can lead to breathing difficulties such as bronchoconstriction.

Although the current state-of-the-science confirms reductions of acid deposition and its precursors would be beneficial, it does not allow us to neatly quantify all the benefits we expect to receive. We believe, however, that it is possible to include some quantitative information on benefits in the areas of aquatic resources, visibility improvements, and public health. In the case of high elevation spruce forests, and materials such as paints and statues, the inability to quantify the expected benefits should not be taken as a sign that there are no benefits in these areas to be derived from reduced emissions of acid rain precursors, particularly sulfur dioxide (SO_2).

Aquatic resources

EPA, under the auspices of the National Acid Precipitation Assessment Program (NAPAP) has conducted extensive scientific research in this area. The National Surface Water Survey encompasses distinct surveys, including The Eastern Lake Survey, The Western Lake Survey, and The National Stream Survey. These studies produced a number of documents which detail the characteristics of surface waters in various regions of the United States. These studies did not directly establish causal relationships but did demonstrate the extent of acidic surface waters in the U.S., and the number of lakes and stream reaches that are potentially sensitive to episodic acidification; that is, those lakes and streams which might become acidic as a result of episodic "shock" such as spring snow melt. The extent of sensitive systems is critical to understanding the importance of reducing acid rain emissions, because we not only want to start on the road to recovering currently acidic surface waters (where acidic deposition is a cause of the acidity), but we also want to prevent the possibility that sensitive systems will become acidic.

Data for the period 1965 to 1981 suggest that surface water sulfate concentrations roughly track trends in sulfur emissions. In the Northeast, sulfur dioxide emissions have decreased in recent years; over the same period, surface water sulfate concentrations have decreased. Sulfate concentrations in streams in the Southeast have also continued to increase. There is general agreement about the connection between sulfur emissions and the sulfate found in surface waters. However, the relationship between sulfate in surface water and surface water acidity requires more careful analysis to focus on the chemistry of sensitive lakes rather than all lakes. The results of this analysis will be contained in the NAPAP State-of-Science papers.

Lakes and streams that have an Acid Neutralizing Capacity (ANC) of less than 0 microequivalents/liter (ueq/L) are considered acidic; that is, they have no buffering capacity. If ANC is less than 50 ueq/L, surface waters may be considered "very sensitive" and may become acidic temporarily as a result of episodic events such as spring snowmelt. This is important because episodic events could have a significant impact on fish during the spawning season.

In the Northeast section of the United States the NSWS sampled a population of about 7,000 lakes greater than 10 acres in size. Of these lakes, approximately 5 percent are acidic and 20 percent are very sensitive to acidification. In the Adirondacks, about 11% of the lakes larger than 10 acres are acidic. If we look at data on lakes in New York collected by the Adirondack Lake Survey Corporation (ALSC), which includes lakes smaller than 10 acres, the number of acidic surface waters increases; for example, about 25% of the lakes less than 10 acres in size were found to be acidic in the ALSC work.

In the Middle Atlantic region there are 110,000 km of streams. About 4.4% of stream lengths are estimated to be acidic and 15.5% are very sensitive. In the Southern Blue Ridge about 8% of the steams surveyed are very sensitive.

Florida lakes are an anomaly. While 12% of the lakes and 22% of the streams are acidic, levels of sulfur deposition in the State are lower than in the Northeast. The relatively high degree of acidity there reflects two groups of lakes. The first group of surface waters, 79% of the acidic streams and 41% of the acidic lakes, are acidic largely as a result of factors other than acidic deposition. This group of surface waters is dominated by natural organic acidity. A second group of acidic lakes is dominated by sulfate, and acid deposition is likely to have played a role in their acidification.

In the Western Lake Survey, there were essentially no acidic surface waters found; however, 16.8% (1745 lakes) of the target population is naturally sensitive to acidification (i.e., ANC < 50 μeq/L). Of five subregions in the West, the Northern Rockies had the third highest estimated number of lakes with low ANC. Most of the lakes with low ANC were located in the Bitterroot Range along the Idaho-Montana border and in the Sawtooth Mountains of Idaho.

Projections of changing surface water conditions as a function of different levels of sulfur deposition scenarios were estimated as part of the Direct/Delayed Response Project (DDRP). The DDRP projects that environmentally beneficial changes in surface water chemistry will occur as a result of continued decreases in atmospheric sulfur deposition in the NE. Based on example deposition scenarios, the DDRP analyses projected that over the next 20 to 50 years a 30% decrease in sulfur deposition would result in a statistically significant reduction in the number of NE lakes prone to episodic acidification shocks due to spring snowmelt. The number of acidic lakes reduced in the region as a result of such a decrease in sulfur deposition was not statistically significant.

DDRP projections indicated that constant or increased sulfur deposition in the Southern Blue Ridge would lead to a statistically significant increase in the number of acidic steam reaches and stream reaches susceptible to episodic acidification shock. A 30% reduction in sulfur deposition would be expected to decrease the extent and rate of this potential future damage.

We have not estimated benefits to Canadian surface waters from emission reductions because the Canadian lake sampling data does not lend itself easily to application of our regional aquatics models, but we can expect results in Canada similar to those in the Northeast section of the United States because the watershed chemistry is similar.

Visibility

Summertime skies in the eastern U.S. are noticeably hazy much of the time. Much of this haze is not, as commonly thought, a natural phenomenon, but is caused largely by manmade pollution. The link between visibility reduction and increased levels of sulfate in the atmosphere is firmly established in the scientific literature. The increase in sulfate levels has been found to be directly related to sulfur dioxide emission patterns. Based on preliminary EPA work, which modelled sulfate and humidity levels, we estimate that a 10 million ton reduction in SO_2 emissions would increase visibility along the east coast 30 to 40% in the most affected areas. Increased visibility translates into aesthetic value, particular in national parks and other scenic vistas, as well as public safety value, in terms of activities such as flying.

Health

A growing body of evidence from epidemiological studies together with laboratory studies of humans and animals suggests that current levels of acid sulfate aerosols may be responsible for a variety of health effects. For example, researchers at Harvard, Brookhaven, Carnegie Mellon, and elsewhere have found a persistent statistical relationship between sulfates and excess mortality. The results suggest that up to 4 to 9% of the annual U.S. mortality may be associated with sulfate exposures (H. Ozkaynak and B.D. Thurston, "Association Between 1980 U.S. Mortality Rates and Alternative Measures of Airborne Particle Concentration,", Risk Analysis Journal, December, 1987). However, there are a number of inherent uncertainties in the mortality studies involving the underlying statistical models. The more recent studies have attempted to address the major criticisms of earlier investigations. Nevertheless, the studies cannot provide the quantitative dose-response information that one would like to have. A Canadian study has consistently found correlations between hospital admissions for respiratory ailments and exposure to sulfates, even after taking ozone into account. Finally, some of the most compelling data is coming from the Harvard "Six City" Study where the incidence of bronchitis in children varies directly with subsequently measured acid aerosol levels. In addition other studies implicate acid aerosols in possible breathing difficulties in asthmatics and children, and raise concern that long-term exposure may contribute to the development of chronic lung disease.

EPA's science advisors recently noted that the cumulative evidence available about sulfates and lung impairment raises clear concerns about the potential health effects of current levels of acid aerosols. These levels will be reduced under the President's proposal, which will benefit public health.

Acid rain results in increased leaching of a variety of radionuclides from soil. Once liberated from soil, these substances can be taken up into plants. Any contamination of agricultural produce would result in an increase in the amount of background radiation among those who consume the produce.

Of perhaps greater concern is the liberation by acid rain of heavy metals from a variety of sources. There has been an increased concern in the U.S. about mobilization of heavy metals such as lead, mercury, and cadmium through drinking water or uptake into crops. Each of these metals has well-described deleterious effects on specific organ systems, and even small doses that produce no apparent immediate impacts on health can be of long-term concern.

Question 2

Provide projections of utility SO_2 emissions and total SO_2 emissions for the period 1980-2020 for 3 scenarios: (1) baseline; (2) implementation of Phase I and II and the cap as set forth in S.1630, and (3) implementation of Phase I and II but no SO_2 emissions cap. Provide projections for EPA's Low and High Cases. For scenarios 2 and 3 indicate the level of the cap and whether emissions would be at the capped level or at a lower level. Provide graphs and the numeric estimates.

Answer 2

The utility SO_2 emission projections are as follows. In some cases these represent more "approximate" or preliminary estimates since detailed modeling analyses have not been conducted for these particular options.

TOTAL UTILITY SO_2 EMISSIONS
(in millions of tons)

	1980	1985	1995	2000	2005	2010	2020
High Base	17.4	16.3	18.2	19.4	20.0	20.8	19-21[a]
Low Base	17.4	16.3	16.6	17.1	16.6	15.7	10-11[a]
S. 1630 High	17.4	16.3	14.7[b]	9.0[b]	8.8[b]	9.0[b]	9[a]
S. 1630 Low	17.4	16.3	13.5[b]	9.6[b]	9.0[b]	9.1[b]	9[a]
S. 1630 High No Cap	17.4	16.3	14.7[a]	9.2[a]	10.0[a]	12.0[a]	13-15[a]
S-1630 Low No Cap	17.4	16.3	13.5[a]	9.7[a]	9.5[a]	10.2[a]	11-12[a]

[a] Approximate estimate, no detailed modeling analysis has been conducted.

[b] Preliminary estimates.

Question 2(a)

An important assumption in these projections is the percent of SO_2 removal in new plants. Has EPA begun to require 95% removal in new coal plants (e.g., recent plants planned in Texas and Virginia)? Could EPA or Congress require 95% removal using the rationale of Best Available Control Technology?

Answer 2(a)

Existing New Source Performance Standards (NSPS) for new coal-fired boilers require 70 to 90 percent SO_2 removal and an emission rate no greater than 1.2 lb/mm Btu. This level of control must be met at all new facilities. Best Available Control Technology (BACT) is applied on a case-by-case basis and can be more stringent than NSPS. An SO_2 removal requirement of 95 percent or greater may have been applied in a few specific cases where it was economically feasible and where other environmental requirements such as Prevention of Significant Deterioration (PSD) rules required it. However, this high SO_2 removal requirement has been an exception rather than usual practice.

Under existing law, EPA does have the authority to require 95 percent SO_2 removal under the rationale of BACT if EPA believes such level of control is feasible and justified. Congress, of course, can require this level of control under any conditions if it chooses to do so.

Question 2(b)

Does the EPA baseline assume 90% removal for all new plants? If so, provide a second set of projections like those requested above with the assumption of 95% removal for all new plants.

Answer 2(b)

The EPA baseline assumes current NSPS which requires 70-90 percent removal. If a 95 percent SO_2 removal requirement were employed for NSPS and assuming it would only affect those plants built after 1995, baseline estimates would be approximately as follows:

TOTAL UTILITY SO$_2$ EMISSIONS

	1980	1985	1995	2000	2005	2010	2020
High Base w/95% NSPS	17.4	16.3	18.2*	19.3*	19.4*	19.1*	16-18*
Low Base w/95% NSPS	17.4	16.3	16.6*	17.0*	16.3*	15.1*	8-10*

* Very approximate estimate, no detailed modeling analysis has been conducted

Question 3

The ICF analysis of the Administration's bill estimates that utility SO$_2$ emissions would decline somewhat from 2000 to 2010. What could cause this? Does the cap effectively become tighter over time?

Answer 3

The forecasted decline in utility SO$_2$ emissions under the ICF analysis of the Administration bill between 2000 and 2010 occurs primarily because, through a drafting error, the bill did not allow non-affected units to retain allowances upon retirement. Indeed, under the bill these units do not receive SO$_2$ allowances but are required to meet an average emission rate requirement. A number of these units are forecast to retire between 2000 and 2010, and as this occurs, the emissions contributed by these units decline. Since, due to the drafting error, these sources have no allowances to retain and sell upon retirement, their retirement makes overall emissions decline; this effect would ultimately lower the cap to about 5.1 million tons per year. (Note that under the Administration bill if an affected unit retires, the overall level in emissions would not decline, because the utility that owns the retired unit would continue to receive SO$_2$ allowances which it could trade.)

The Administration had not intended for this cap decrease to occur. Rather, it had intended that SO$_2$ emissions be reduced by 10 million tons from 1980 levels, leaving utility emissions at a level of about 8.9 million tons per year. The drafting error which caused the cap decrease has been corrected in S. 1630; therefore, S. 1630 would not cause a decreasing cap over time.

Question 4

The ICF analysis estimates that, in both the High and Low cases (Flexible), the marginal cost of trade decreased from 2000 to 2005, then increases from 2005 to 2010. Why does this occur? What does EPA project the marginal cost of trade to be in 2015 and 2020? What is the long-term expectation post-2020? Explain the reasoning underlying the expected post-2010 trends.

Answer 4

The marginal costs of SO_2 reductions declines somewhat between 2000 and 2005 because of (1) the repowering that is forecasted to occur, and (2) the addition of some new plants which allows for greater flexibility in dispatching for certain utilities. After 2005, a very large number of new plants are forecast which increases the marginal reduction costs because of the offset requirements.

The marginal cost of reductions after 2010 are much more difficult to estimate given a large number of uncertainties with respect to expected long-term growth, conservation and energy efficiency, use of renewables, among other factors. Under EPA's Low Case Scenarios the demand for allowances (and hence the marginal costs) would be expected to decline after 2010 as substantial numbers of "affected" plant retirements more than offset the emission increases from new capacity. There could be some increase in the marginal cost of allowances in the high case (which assumes robust electricity demand growth and few retirements). However, by 2020 the marginal costs would begin to decline under the high case, also, as plant retirements increase. Note that improvements in technology expected over time and encouraged by the emissions cap would tend to reduce the marginal costs of control.

Question 5

What would be the effective caps on utility emissions and total emissions in the Administrations original bill? Are these caps essentially unchanged in S. 1630?

Answer 5

Regarding sulfur dioxide emissions, the objective of the Administration bill is to reduce total emissions by 10 million tons below the 1980 level by the end of the year 2000, and to maintain that reduction permanently. In order to meet this objective, utility emissions would be limited to about 8.9 million tons per year. Due to a drafting error, the original Administration bill did not allow non-affected units to keep allowances upon retirement; as a result, as non-affected units retired, post-2000 emissions were forecast to decline further with time below the 8.9 million ton cap, ultimately to about 5.1 million tons per year in the very long run. This drafting error has been fixed in S. 1630, and preliminary forecasts show nearly the same results as the Administration bill would have achieved without the drafting error.

Neither the Administration bill nor the Senate bill limit non-utility emissions. EPA has forecast these emissions to remain nearly constant after 1985, with the exception of an emissions decrease of 0.4 million tons per year from the desulfurization of diesel fuel. Since EPA expects no increase in industrial emissions, it did not consider the inclusion of provisions to protect against such an increase. S. 1630, however, does contain a provision calling for EPA action, including the promulgation of standards for industrial emissions, if these emissions do increase beyond present levels.

Question 5(a)

What was the basis for choosing the level of caps in the Administration bill?

Answer 5(a)

The level of reduction was chosen because there is now sufficient evidence that sulfur dioxide reductions on the order of 10 million tons will reverse the deterioration of our lakes and streams that is attributable to acidic deposition and allow most of these systems to recover chemically and have the opportunity to recover biologically; significantly improve the frequency of clear days and the extent of visual range in the East and limit visibility degradation in the West; reduce health risks to millions of people in the eastern United States; and reduce materials damage, such as corrosion of metals, soiling, and deterioration of paint and the defacing of culturally important monuments and markers. The "cap" provision assures that these benefits, once achieved, will be permanent.

Question 5(b)

Why did the Administration propose to write the level of emission cap into law now as opposed to giving EPA administrative power to set a cap level now or in the future?

Answer 5(b)

The primary reasons for writing the emission reduction levels into law is the elimination of uncertainty on the part of utility planners and to ensure environmental protection. The achievement of the mandated reductions requires a planning and implementation period on the order of several years, and utilities need to know that far in advance what their requirements will be. Since the amount of required reduction and the need to maintain it is now known, it is possible to embody it in the law, thereby preventing uncertainty about the content and timing of future regulatory requirements. Also, until a specific cap level is set, there can be no market in allowances.

Question 5(c)

Some have argued that Congress or EPA would have substantially better information on which to base an emission cap decision if the decision were deferred until NAPAP completed its research, or until other research was conducted specifically on the appropriate level at which to cap emissions. What is the EPA's response to this argument?

Answer 5(c)

The Administration believes that sufficient evidence now exists to support the conclusion that sulfur dioxide reductions of 10 million tons will yield the environmental benefits outlined in the answer to question 5(a) above and that those benefits will not accrue or be substituted if emissions do not remain at the lower level. It is not thought likely that further evidence forthcoming in the next few years will undermine this conclusion. At the same time, waiting for further research would mean endorsing several more years of excessive sulfur dioxide emissions.

Due to the evidence of adverse impacts in the aforementioned areas, it would be desirable to reduce sulfur deposition immediately. However, for a number of practical reasons, such as the availability of control equipment and alternative fuels, and for economic reasons, particularly regarding the impact on ratepayers and coal mining communities, the Administration proposed the schedule embodied in its bill. The Agency believes that the schedule proposed by the Administration is the best balance of what we know about the science and what disruption we can reasonably tolerate.

Question 6

S. 1630 provides that EPA write regulations allowing the transfer of allowances within each of two major geographic regions.

(a) Does the impact of a ton of SO_2 emissions vary significantly according to the region or air basin from which it is emitted? If yes, provide one or more examples.

(b) Describe the advantages and disadvantages of a regional approach to setting emission cap levels, i.e., one that would set emission caps for different regions of the country based on the benefits and costs of emission reductions in each region and affected air basins, and that paid particular attention to emissions affecting the most sensitive ecosystems.

Answer 6

(a) The impact of a ton of SO_2 emissions can vary depending on the location of the source. Whether that variation is significant depends on many factors, not the least of which is one's definition of "significant."

Ecosystems in different parts of the country have undergone varying amounts of damage, and may undergo damage in the future from SO_2 emissions. Such damage is a function of the level of emissions, the general location of the emitting source(s), and the characteristics of the environment receiving pollution.

As you know, combustion products are emitted, and some are carried by the atmosphere and transformed with the help of sunlight into sulfates and nitrates and other sulfur-particulate complexes, which then settle or wash out of the atmosphere. Large-scale atmospheric motion transports the pollution 300 to 500 (or more) miles downwind, thus assuring an interstate problem. So long as sources can affect receptors 300 to 500 miles downwind, the problem of defining control regions is compounded by atmospheric transport in a 500-mile wide margin at the edge of and such regions.

Research shows that the entire nation can benefit from controls on acidic deposition. While the greatest extent of ecological damage has occurred on glaciated soils of the Northeast, the thin soils and watersheds of the West are at risk because they have even less capacity to neutralize acids. Also, the soils of the South are currently adsorbing sulfur deposited there, and if the soils become saturated, it is likely that sulfates will pass through to the aquatic systems and acidify them.

One can extrapolate from this aquatic example to the broader perspective that the impact of a ton of SO_2 on aquatic resources, forests, materials, visibility and health is a function of several things: current concentrations and loadings (resulting from current patterns of SO_2), current damage/impairment, future concentrations/loadings as a result of the ton increase (taking into account the location of the source), sensitivity of each environmental category of concern to the new concentration/loading, and the way these changes to the environment are aggregated and valued.

(b) Neither the Administration proposal nor S. 1630 set caps on a regional basis. Both have national caps. Clearly, the advantage of a regional approach to setting emission caps is that the stringency of the cap can be more finely "tuned" to local/regional considerations of benefits and cost. However, the data, and particularly the analytical tools, are not currently, and may not be for some time, of sufficient resolution to define the regions and the various cap levels with reasonable confidence levels.

We currently envision two trading regions for existing source allowances, East and West, whose boundaries would depend on further analysis and on comments that might be received during public comment on proposed rulemaking. The rationale for two trading regions rests primarily on fundamental differences between the East and West in their environmental characteristics, population density and growth, source characteristics, and coal quality.

In the East, a unique confluence of location of coal deposits, industrial development, technology, population, geographic size of states, rainfall patterns, and glacial history create an acidic deposition problem for thin granitic soils, particularly in the Northeast, Upper Midwest and Canada, that are downwind of major combusters of high-sulfur coal. In the West, thin soils in the Rockies have little or no buffering capacity and are at risk from increases in acidic deposition. The visual range of the West's expansive scenic vistas are also at risk of being significantly reduced due to increases in precursors of acid rain.

Given the greater potential for growth and the generally higher marginal control costs in the West, we believe that in the absence of two trading regions there would be a tendency for greater emissions growth in the West without the two trading regions.

Question 7

Did the Administration consider such a regional approach to setting emission cap levels in formulating its original proposal? If so, why did it reject it?

Answer 7

The Administration did not consider a regional emission cap approach because the complexities cited above made determining any additional benefits beyond those achieved by the national reduction extremely difficult and because potential economic costs might result from constraining the market for offsets.

Question 8

The Edison Electric Institute has proposed an alternate method of implementing an emissions cap by a variable emission rate limit. Compare the advantages and disadvantages of the method in S. 1630 and the method proposed by EEI.

Answer 8

The cap in S. 1630 has several advantages and only one disadvantage. On the other hand, the alternate cap proposed by EEI has several disadvantages and only one advantage. These advantages and disadvantages are discussed below.

The advantages of the cap in S. 1630 are:

o The fixed cap and the allowance trading system in S. 1630 assures with reasonable certainty that emission reductions, once achieved, will be permanent.

- The flexible trading approach in conjunction with the cap in S. 1630 should allow a least-cost solution to the problem reducing national costs by about 20 percent compared to other proposals.

- The cap approach under S. 1630 both encourages and credits energy conservation and the implementation of increased energy production efficiencies since both of these measures reduce emissions (but do not necessarily reduce emission rates).

- The cap approach under S. 1630 also promotes technology innovation in energy production and pollution control since costs can be reduced and profits increased with these innovations. This is a national economic advantage since there is a world wide market for these technologies.

The one disadvantage of the cap in S. 1630 is:

- There is a perception in the utility industry that hoarding will occur under the cap approach, making it difficult for new sources to obtain needed allowances, and thereby inhibiting economic growth. The Administration does not believe that such hoarding will occur; moreover, S. 1630 contains a provision for making the government a "seller of last resort" in the unlikely event that hoarding does become a problem.

The advantage of the EEI approach is:

- The EEI rate cap is easier for some utilities to implement because it does not require them to integrate overall environmental protection measures in their energy planning and system operation.

The disadvantages of the alternate EEI cap approach are:

- The EEI approach is based on the achievement of specific emission rates. Compliance with emission rates does not assure that desired emission tonnage goals will be achieved as electricity demand increases. Therefore, any emission reductions achieved are likely to be eroded in later years.

- As energy demands increase, emission rates of existing sources must be reduced in order to meet overall emission tonnage goals. The need for these periodic adjustments adds uncertainty in the planning for pollution controls at both new and existing sources as well as economic uncertainty for the companies and their customers.

- Since the EEI cap is based on emission rates only, it provides no incentives for energy conservation measures, improved efficiencies in energy production, or other technology innovations. Without the energy efficiency and technology incentives, energy production and emissions would be more likely to increase than under an emissions cap and this would ultimately require stricter emission controls and higher costs for achieving necessary environmental goals.

Question 9

Has EPA attempted to corroborate the cost estimates of the ICF model with estimates of control costs from STAR reports or any other source? If yes, what were the results? If no, why has no corroboration been attempted?

Answer 9

It is important to understand the difference between the modeling approaches used by ICF and those used by States during the State Acid Rain (STAR) Program. National models such as the Coal and Electric Utility Model (CEUM, used by ICF) and the Advanced Utility Simulation Model (AUSM, to be used by NAPAP) build estimates of national control costs from unit-specific data, from estimates of national coal supply, and from the national dispatching behavior of electric utilities.

The STAR investigations were designed to yield cost estimates at three levels: basic unit-specific control costs, total system-wide costs, and optimization of control costs with SO_2 reductions. The unit-specific control costs were developed for a range of control techniques at electric utility boilers and include the following costing methodologies, the TVA Physical Coal Cleaning model, the TVA-Shawnee model, the EPRI retrofit FGD model, IAPCS-II, the Tennessee STAR method and the Florida Acid

Rain Model (FARM). Total system-wide costs were investigated by Illinois and Wisconsin using state-level versions of the AUSM. These two studies explored the difficulties of constraining a model designed for national use to the state level, and concluded that complex national models were not well suited to the needs of state air quality agencies. The optimization efforts were conducted by Wisconsin using the Sulfur Emission Reduction Optimization Program (SEROP, developed by Wisconsin Power and Light) and by the Northeast States for Coordinated Air Use Management (NESCAUM) using a model developed by NESCAUM and E.H. Pechan and Associates.

Modeling investigations conducted during the STAR Program were decentralized efforts to help meet the implementation needs of States. The models used in some STAR projects were neither designed nor used to develop national cost estimates; however, the STAR projects provided a great deal of useful information on unit-specific control costs. Results of the State efforts improved the quality of data and the level of understanding of those portions of the national models that rely on unit-specific data.

An overview of control cost methodologies was conducted for EPA during the STAR Program by the Midwest Research Institute. Results are documented in a Final Report entitled "Review of Methodologies for Estimating Control Costs for Acid Rain Precursors". A copy of this report is attached for your review.

Due to these fundamental differences mentioned above between the modeling approach used by ICF and those used by the States during the State Acid Rain (STAR) Program, the STAR estimates cannot be compared with the ICF model estimates.

Question 10

In response to a question from the July 11, 1989 Energy R&D Subcommittee hearing, DOE replied that "The fear that the WEPCo decision may provide a strong motive not to participate in the clean coal program is a well-founded one." What is EPA's view on the effect of the WEPCo decision on DOE's clean coal technology program?

Answer 10

In late 1988 and early 1989, EPA issued a series of determinations that a proposed life extension project at Wisconsin Electric Power Company's (WEPCO's) Port Washington plant would be subject to both PSD and NSPS. The company planned $80 million worth of renovations at aged, deteriorated boilers (one of which has been inoperable for several years), extending the units' life by 20 years rather than retiring them in the next few years as previously planned. The renovations included the unprecedented replacement of steam drums and air heaters. EPA found that these renovations were nonroutine changes that would (at 3 of 5 units) increase current actual capacity, and hence, hourly emissions for NSPS purposes. EPA also found that potential emissions after the change would be significantly greater than actual emissions prior to the change, and hence, PSD would apply as well.

A central theme of the Agency's position in the WEPCO matter is that one of the key purposes of the CAA is to apply new source requirements where there is a substantial capital investment in pollution-generating facilities that may result in more pollution or pollution for a longer period of time. We are awaiting a decision from the court of appeals on WEPCO's petition for review of the EPA actions.

We cannot provide a blanket exemption for permanent repowering projects under the current CAA. Therefore, until the CAA is changed, the WEPCO decision could affect permanent repowering projects because they are major modifications designed to extend the life of existing plants, making them essentially "new" plants in the eyes of the CAA. If a repowering project has a significant net emissions increase, PSD and best available control technology (BACT) would likely apply. If there is no significant net emissions increase, BACT would not apply. Recently, the First Circuit Court of Appeals issued a decision (Puerto Rican Cement Co. v. EPA) which strongly endorses EPA's actual-to-potential approach when determining whether there is a significant net emissions increase.

EPA is currently working on an interpretive ruling to exempt from NSPS and NSR requirements temporary and permanent CCT projects that reduce pollution. This interpretive ruling would not exempt projects like the WEPCO renovations or permanent repowering projects that primarily extend the life of a plant or increase emissions. The CCT interpretive rulemaking has high priority within the Agency. We believe the interpretive rule can be published before May of this year. This interpretive ruling should minimize the concerns of potential CCT program applicants.

Question 11

What policy guidance regarding the applicability of the WEPCo decision has been issued by EPA to date? Does EPA support a legislative exemption of new source review for existing projects funded under the DOE Clean Coal Technology Program and clean coal technologies that are used to comply with any current and future Clean Air Act requirements?

Answer 11

EPA has not yet issued policy guidance regarding the applicability of the WEPCO decision. However, in January, the

Agency intends to comment on the public record in support of a decision made by the State of Indiana with respect to a CCT project. The State decided that when the Northern Indiana Public Service Company Bailly Plant installs control equipment as part of the CCT program, it will not trigger NSR and NSPS requirements for the source. Also, as stated in our response to Question 10, we intend to issue an interpretive ruling before May that should minimize the impact of the WEPCO decision on the CCT Program.

EPA supports the language contained in sections 508 and 515 of S. 1490.

__Question 12__

Please look at the cost of compliance with the President's proposed Clean Air Act Amendments. What is the increased cost of compliance due to the implementation of the in-state coal requirements? What states are most likely to benefit from this provision? Do you have an estimate of the number of tons of coal or the number of high sulfur coal mining jobs that would be protected by this provision?

__Answer 12__

We have not yet fully analyzed this provision. We will analyze the cost of "local coal" protection with respect to the recent Senate Bill and the results will be available shortly.

__Question 13__

Should industrial sources (in addition to utilities) be forced to make reductions in SO_2 and NO_x? If so, how would they fit into the emissions allowance program as described in the President's proposal? How would they fit into the emission allowance program contained in S. 1630, as ordered reported by the Senate Committee on Environment and Public Works on November 16, 1989? What regional impacts in terms of cost of compliance would result from reductions required by both proposals?

__Answer 13__

The Administration does not believe that industrial sources should be included in the purview of the proposed acid rain program for four reasons. First, industrial facilities are consumers of electricity and therefore would be paying their share of electricity rate increases. Second, many industrial facilities are required to reduce pollution under Title I and III of the proposed amendments. Third, it would be impractical to include them because there are about 10 times as many industrial facilities as there are utility boilers; many have dozens of emission points. And there are numerous categories of industrial sources, each requiring different control approaches. Moreover, in the aggregate, industrial sources emit less than half the emissions of utility boilers. Therefore, administrative and compliance costs per ton removed, in many cases, would be higher than for utility sources. Fourth, if we were to exclude the smaller and cleaner facilities from requirements, as we did for utility boilers, there would be few emission reductions gained by the mandatory inclusion of this category. However, since there are opportunities for cost-effective SO_2 reductions scattered throughout the industrial sector, the Administration and Senate proposals allow sources to elect into the allowance system.

Question 13(a)

Do you have any estimate of the emissions savings projected to result from the inclusion of the election for additional sources provision in the legislation? If so, please provide.

Answer 13(a)

We have not conducted analyses which estimate the potential cost savings from this voluntary inclusion. We have, however, estimated that 0.5 million tons per year of reductions are available at industrial sources at a cost less than $400 per ton.

Question 13(b)

Please provide data on SO_2 and NO_x emissions by industrial category.

Answer 13(b)

The requested data is provided in Attachment 2.

Question 14

How many states would qualify for the clean states credit provided for in S.1630 as ordered reported by the Committee on Environment and Public Works? Please identify them.

Answer 14

Seven states would qualify: Kansas, Minnesota, North Dakota, Montana, Wyoming, New Mexico, and Utah.

Question 15

Please provide an estimate of the net change in emissions and compliance costs by year and by state resulting from the inclusion of this provision.

- **What is EPA's view of the efficiency and equity effects of this provision?**

Answer 15

We have not yet analyzed the detailed effects of this provision relative to the Senate bill. However, our preliminary indication is that it would result in about 0.2-0.3 million tons less SO_2 reductions.

EPA does not believe this provision is equitable since it essentially exempts certain high emitting sources from control because they happen to be in States where other units are scrubbed, and (if the 10 million ton goal is to be achieved) could shift the control burden to lower emitting sources that happen to be in States with less scrubbed capacity.

Question 16

Please provide a list of all states in which less than 150,000 tons of sulfur dioxide were emitted by utility steam-electric generating units in 1985. List current emissions and emissions projected for the year 2005.

Answer 16

UTILITY SO_2 EMISSIONS (MTons)

State	1985	Low Base 2005	High Base 2005
ME	10	0	18
NH	74	29	49
VT	1	0	0
RI	2	0	1
CT	56	12	51
NJ	97	110	160
DE	63	37	66
VA	131	189	296
MS	113	80	95
MN	124	143	143
ND	124	149	149
SD	32	42	69
KS	117	222	229
NE	45	90	96
AR	69	125	127
OK	80	163	206
LA	67	105	128
MT	22	110	121
WY	135	81	116
CO	84	108	130
UT	27	56	65
NV	35	79	102
NM	114	61	70
AZ	104	149	166
OR	2	18	18
WA	85	90	90
CA	3	0	0

Question 17

Please provide a list by state of coal and oil-fired units below 75 MWe with an actual 1985 emission rate above 1.20 lbs./mmBtu. What were the total emissions from these plants (by state) in 1985, and what are the projected emissions by year between now and the year 2000?

Answer 17

A list of these units is given in attachment 1. National historical and projected emissions are noted below:

SO_2 EMISSIONS AT SMALL UNITS ABOVE 1.2 LBS.
(in millions of tons)

	1985	High Base 2000	Administration Bill High Flexible Case 2000
Total U.S.	0.6	0.5	0.4

We have not developed year-by-year estimates for this class of plants although they are generally expected to decline over the 1985-2000 period due to retirements. Note that these emissions could vary considerably depending on the extent to which they retire, the type of acid rain legislation, and underlying economic growth.

Supplemental Question 1

Compare the advantages and disadvantages of auctions or revenue-neutral auctions (one-time or periodic) as methods of allocating emission allowances relative to the method proposed in S. 1630. In formulating the Administration's original bill, did the EPA consider such auctions?

Answer to Supplemental Question 1

Auctions were considered as a method for allocating allowances under the Administration bill. However, it was found that such a system affords no advantages over the direct allocation system ultimately adopted, and can have distinct disadvantages. If all allowances were auctioned rather than distributed, the initial costs of obtaining allowances must also be factored into the cost to utilities of complying with the program. Nationally, the costs to electric utilities would increase by about $4 billion per year to account for the cost of obtaining allowances. If auction revenues were then redistributed in proportion to the allowances in the Administration bill, the net impact on individual utilities would, to a first approximation, be unchanged. If auction revenues were not distributed back to utilities, utilities in the hardest-hit states would suffer a greater loss than utilities in other states relative to the Administration bill, which automatically vests a large share of total allowances in the hardest-hit states.

Supplemental Question 2

Under the provisions of S. 1630, what actions could the EPA take if the emission trading system does not work as intended?

Answer to Supplemental Question 2

Under Section 403(a)(2) of S. 1630, EPA must retain 2% of affected unit allowances in a reserve, and must sell these allowances at a price of $1500 per ton to owners or operators of new units in the event that they cannot buy allowances elsewhere. EPA is given the discretion to determine by regulation the circumstances requiring such sale, as well as the requirements and procedures governing the sale.

Supplemental Question 2

What are the advantages and disadvantages of giving EPA discretionary power to modify the system if it does not work as intended? In formulating the Administration's original bill, did the EPA consider any such discretionary powers?

Specifically, what are the advantages and disadvantages of giving EPA power to create increased allowance set-asides to be sold or auctioned if the emission trading system does not work as intended?

Answer to Supplemental Question 2

A major disadvantage of giving EPA discretionary power to modify the system for allowances is that the attention of participants in the market will be diverted towards securing benefits from the exercise of this discretion. Discretion is an open invitation for efforts to overturn the emissions cap by "striking" against the market. It is hard to imagine how the distraction of discretionary EPA intervention could make the market work better.

Discretion should be distinguished from carefully pre-specified provisions to provide a back-up mechanism to deal with concerns regarding the future availability of allowances. S.1630, for example, includes a provision for a last resort allocation mechanism, so that utilities planning new units can be assured that allowances will be available at a predictable price, and that the emissions cap would be maintained, since the 2% reserve is part of the overall total of allowances constituting the cap.

In formulating the Administration bill, such mechanisms were not considered, and the Agency still doubts that they will be necessary. However, others do see such a need, and the method embodied in S. 1630 appears to be a reasonable way to answer it.

Questions on Hazardous Air Pollutants

There are seven specific questions raised with regard to the impacts of the hazardous air pollutant provisions on the oil and gas industry:

Question, Part 1

Definition of "major source" as it applies to oil and gas production units.

Answer, Part 1

A "major source" is defined as a source which emits 10 tons of a single pollutant of 25 tons of any combination of listed pollutants. In determining whether a source is major, EPA or the State would review all emissions of any listed pollutant within a contiguous area under common control. Given this definition, all emission points under common control within a given production field would likely be included in a major source. Although the EPA has gathered some information on emissions from oil and gas production facilities, we do not have enough information to judge the impacts of the major source definition on this source category at this time.

Question, Part 2

Negligible risk.

Answer, Part 2

There are exemptions from the air toxics regulations under both S. 1490 and S. 1630 upon demonstration that the emissions from a facility cause negligible risk. One of the early activities that will occur pursuant to the enactment of the amended Clean Air Act will be to develop guidance on how negligible risk will be determined. The EPA has published several guideline documents on risk assessment. It is likely that the principles from the existing guidelines will be employed in developing the negligible risk guidance.

Question, Part 3

What is the state of the database for emissions of hazardous air pollutants for oil and gas operations?

Answer, Part 3

EPA's Office of Air and Radiation has a limited information base on emissions hazardous air pollutants by oil and gas production. This information would have to be substantially augmented and updated before any regulatory action could be promulgated under the amended section 112 of the Clean Air Act.

Question, Part 4

Would oil and gas field units be regulated as point or area sources?

Answer, Part 4

Due to the limited information available on this industry we cannot determine at this time whether the oil and gas production industry would be listed as a major point source category or an area source category. Both S. 1630 and S. 1490 define a major source as emitting 10 tons of any single pollutant or 25 tons of any combination of listed pollutants. The determination of whether this industry would be classified as a point or area source category would be based on the amount and distribution of the emissions of hazardous air pollutants. In addition under the provisions of S.1490, EPA can define a lower threshold for a major source depending on the toxicity of the substances emitted.

Answer, Parts 5 through 7

These questions all ask what will constitute maximum achievable control technology determinations for different segments of the oil and gas industry.

At this point no MACT determinations have been made for any source categories. It is likely that this process will be conducted on a case-by-case basis when the source categories are under regulatory consideration. The definition of MACT for existing major sources is based on the control technologies in use at the best controlled similar facilities (for new sources the definition is based on the single best controlled similar facility). Although we cannot specifically define what will constitute MACT for this industry at this time, the definition of how MACT will be determined makes it clear that the required emissions reduction will be no more and no less stringent than the best controls achieved in practice. For area sources the control requirements are defined as generally available control technology (GACT). The definition of GACT would also occur on a case-by case basis.

QUESTIONS ON ELECTRIC UTILITIES

Question 1

Explain the rationale behind section 112(m) of the Clean Air Act that would be added under Title III of S. 1490. This provision would direct the EPA to study the hazards to public health after the implementation of acid deposition controls under Title V.

Answer 1

Electric utilities have already been designated for regulation under Title V, "Acid Deposition Control," of the Administration's proposal. The cost to the utility industry for Title V is estimated to be $3 to $4 billion dollars per year. Because of the quantity and variety of emissions released from electric utilities, they are likely to be considered major sources under Title III, "Hazardous Air Pollutants," for which maximum achievable control technology standards could be developed. However, our current information suggests that the exposure to air toxics from utilities could be extremely low in the vicinity of power plants. In addition, preliminary information suggests that if MACT controls are required, they could cost as much as $7 billion per year in addition to the costs associated with Title V. Because of the potential cumulative impact of all of the costs on utilities and their customers, the Administration believes it is prudent to do a detailed study on air toxics from electric utilities prior to the development of any standards for air toxics from these sources.

Question 2

What is the current base of knowledge with respect to emissions of hazardous air pollutants listed under Title III of S.1630 and Title III of S.1490 from electric utility boilers and the public health effects of such emissions? Which of the listed air pollutants are emitted by electric utility boilers?

Answer 2

The Agency has developed emission factors and performed a preliminary risk assessment of the electric utility industry's emissions for a limited number of air pollutants. Currently, there are documented emission factors for 11 pollutants (arsenic, beryllium, cadmium, copper, chromium, mercury, manganese, nickel, formaldehyde, polycyclic organic compounds [POM], and radionuclides) emitted from utility coal and oil combustion boilers. These emission factors have been developed for various combinations of fuel type, boiler configuration, and type of control device. In addition, we have included for the above matrix of boiler combinations crude emission factor estimates for six other air pollutants: selenium; lead; vanadium; phosphorus; fluorides; and chlorides. Our preliminary risk assessment was conducted for those pollutants known or suspected of being human carcinogens, namely arsenic, beryllium, cadmium, chromium, formaldehyde, POM and radionuclides. This study indicated that the estimated cancer risk levels are lower or considerably lower than those associated with other source categories which the Agency has regulated. Noncancer effects have not been studied, but, based on the results of the cancer risk assessment, we believe such effects are not very significant for those pollutants studied.

The Agency believes that the Title III list of toxic air pollutants may contain other pollutants which may be emitted from the electric utility industry; however, there is little available data to provide an extensive and accurate list of those pollutants.

Question 3

To what extent will the emissions controls required under other Titles of S. 1630 and S. 1490 reduce or eliminate emissions of other hazardous air pollutants?

Answer 3

Any reduction in the emissions of air toxics from electric utilities as a result of the other Titles in S. 1630 or S. 1490, depends on the specific measures which different power plants would chose to comply with any other requirements in other Titles. As you know, both S. 1630 and S. 1490 allow flexibility to electric utilities on how to best meet their acid rain control requirements. At the current time, no estimates have been made of any impacts on air toxic emissions as a result of these other requirements.

Question 4

For purposes of electric utility boilers, what constitutes Maximum Available Control Technology (MACT) under Title III of S. 1630 and S. 1490?

Answer 4

The selection of MACT for electric utility boilers will be determined in the course of implementing the air toxics provisions. The Administration bill, S. 1490, requires a study of the emissions and accompanying public health hazard of this source category before any decision is made on appropriate MACT. S. 1630 requires a MACT decision if the source is determined to be a major source.

While a MACT decision has not been made for electric utility boilers it is possible to discuss the potential range of control options. Control options could range from selecting fuel stocks with lower toxic emissions potential or adding or upgrading existing particulate control equipment. Control equipment choices could range from upgrading electrostatic precipitators, installing new baghouse particulate collectors or adding scrubber units. Any MACT decision will have to take into account the nature of both the particulate and gaseous toxic emissions that need control, the current level of control technology in use, the cost of additional control, the toxic emissions potential of various fuels, and the toxic emissions portfolio that exists after the implementation of acid rain controls.

A preliminary comparative cost analysis performed for EPA analyzed different control scenarios for both coal and oil fired boilers. This analysis concluded the following:Costs for control of toxic emissions from the coal-fired boiler segment of the electric utility industry ranged from $630 million (meeting the current NSPS particulate standard by installing or upgrading particulate controls on all coal boilers requiring such control) to $1.9 billion net annualized costs (installation of new baghouses on all coal fired boilers with particulate emissions greater than 0.02 lbs/MMBtu). Cost estimates include operating and annualized capital. Costs for control of oil-fired boiler toxic emissions ranged from $150 million (fuel switching to natural gas) to $660 million (installing or upgrading ESPs to meet NSPS) annualized. If scrubbing were determined to be the appropriate MACT for boilers (for control of gaseous toxic emissions in particular) an upper estimate of the costs of adding scrubbers to those boilers that are not already scrubbing due to acid rain legislation would cost approximately $7.3 billion annually. A main part of the administration's utility boiler study however will be to find the most cost-effective means of controlling harmful levels of gaseous and particulate emissions.

Question 5

To what extent will the "chlorine amendment" to Title III of S.1630 relieve electric utilities from compliance with the requirements of Title III? Will the "chlorine amendment" prevent electric utility boilers from qualifying as major sources under Title III as the consequence of the aggregation of chlorine emissions with emissions of other hazardous air pollutants listed in Title III?

Answer 5

The extent to which the "chlorine amendment" would provide relief from Title III for the electric utility industry is not clear. The amendment prohibits the regulation of chlorine emissions from these facilities for three years following enactment but does not restrict the regulation of other nonchlorine containing emission constituents. Based on a preliminary study, it is likely that this industry, or a subcategory of the industry, would be identified as a major point source category based on the combined nonchlorine emissions from the sources. Though regulation of the chlorine-containing constituents would be prohibited, emission standards for other constituents of the emissions, such as the toxic trace metals listed under Title III, could be required. With this approach, however, the air pollution control technologies selected to meet any nonchlorine pollutant emission standards may not be effective in reducing chlorine emissions which may be regulated at a later date. Also, the need for any toxic pollutant standards has not yet been demonstrated. For these reasons, we believe a preferable alternative is the study envisioned in the Administration proposal. Under this provision, the regulation of electric utility boilers is precluded pending an evaluation of the industry (within three years of enactment).

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ATTACHMENT 1

LITTLE DIRTIES

	UTILITY	PLANT	UNIT
** STATE AL			
AL	ALABAMA ELEC COOP, INC	LOWMAN	001
AL	ALABAMA ELEC COOP, INC	MCWILLIAMS	001
AL	ALABAMA ELEC COOP, INC	MCWILLIAMS	002
AL	ALABAMA ELEC COOP, INC	MCWILLIAMS	003
AL	SO CO:ALABAMA POWER CO	CHICKASAW	003
AL	SO CO:ALABAMA POWER CO	GADSDEN NEW	001
AL	SO CO:ALABAMA POWER CO	GADSDEN NEW	002
AL	SO CO:ALABAMA POWER CO	GORGAS	005
** STATE CO			
CO	CENTEL (CO)	CLARK	001
CO	CENTEL (CO)	CLARK	002
CO	TRINIDAD MUNICIPAL PWR &	TRINIDAD	001
CO	TRINIDAD MUNICIPAL PWR &	TRINIDAD	002
** STATE DE			
DE	DOVER ELECTRIC DEPARTMEN	MCKEE RUN	001
DE	DOVER ELECTRIC DEPARTMEN	MCKEE RUN	002
** STATE FL			
FL	FLORIDA POWER CORPORATIO	HIGGINS	003
FL	KEY WEST, CITY OF, THE U	KEY WEST	001
FL	KEY WEST, CITY OF, THE U	KEY WEST	002
FL	KEY WEST, CITY OF, THE U	KEY WEST	003
FL	KEY WEST, CITY OF, THE U	KEY WEST	004
FL	KEY WEST, CITY OF, THE U	KEY WEST	005
FL	KEY WEST, CITY OF, THE U	STOCK ISLAND	001
FL	SO CO:GULF POWER CO	SCHOLZ	001
FL	SO CO:GULF POWER CO	SCHOLZ	002
FL	TAMPA ELECTRIC COMPANY	HOOKERS POINT	002
** STATE GA			
GA	CRISP COUNTY POWER COMMI	CRISP	001
GA	SO CO:GEORGIA POWER CO	ARKWRIGHT	001
GA	SO CO:GEORGIA POWER CO	ARKWRIGHT	002
GA	SO CO:GEORGIA POWER CO	ARKWRIGHT	003
GA	SO CO:GEORGIA POWER CO	ARKWRIGHT	004
GA	SO CO:GEORGIA POWER CO	MCMANUS	001
GA	SO CO:GEORGIA POWER CO	MITCHELL, W	001
GA	SO CO:GEORGIA POWER CO	MITCHELL, W	002
GA	SO CO:SAVANNAH ELECTRIC	PORT WENTWORTH	001
GA	SO CO:SAVANNAH ELECTRIC	PORT WENTWORTH	002
** STATE IA			
IA	AMES, CITY OF ELECTRIC U	AMES	005
IA	AMES, CITY OF ELECTRIC U	AMES	006
IA	AMES, CITY OF ELECTRIC U	AMES	007
IA	CEDAR FALLS UTILITIES	STREETER	007
IA	CENTRAL IOWA POWER COOPE	FAIR STATION	001
IA	CENTRAL IOWA POWER COOPE	FAIR STATION	002
IA	CORN BELT POWER COOP	HUMBOLDT	001
IA	CORN BELT POWER COOP	HUMBOLDT	002
IA	CORN BELT POWER COOP	HUMBOLDT	003
IA	CORN BELT POWER COOP	HUMBOLDT	004
IA	CORN BELT POWER COOP	WISDOM, EARL F	001
IA	FAIRMONT PUBLIC UTILITIE	FAIRMONT	003
IA	FAIRMONT PUBLIC UTILITIE	FAIRMONT	004
IA	FAIRMONT PUBLIC UTILITIE	FAIRMONT	005
IA	INTERSTATE POWER COMPANY	DUBUQUE	003
IA	INTERSTATE POWER COMPANY	DUBUQUE	004
IA	INTERSTATE POWER COMPANY	KAPP, M L	001
IA	INTERSTATE POWER COMPANY	LANSING	001
IA	INTERSTATE POWER COMPANY	LANSING	002
IA	INTERSTATE POWER COMPANY	LANSING	003
IA	IOWA ELECTRIC LT & PWR C	6TH STREET	004
IA	IOWA ELECTRIC LT & PWR C	6TH STREET	007
IA	IOWA ELECTRIC LT & PWR C	6TH STREET	008
IA	IOWA ELECTRIC LT & PWR C	PRAIRIE CREEK	001
IA	IOWA ELECTRIC LT & PWR C	PRAIRIE CREEK	002
IA	IOWA ELECTRIC LT & PWR C	PRAIRIE CREEK	003
IA	IOWA ELECTRIC LT & PWR C	SUTHERLAND	001

LITTLE DIRTIES

	UTILITY	PLANT	UNIT
IA	IOWA ELECTRIC LT & PWR C	SUTHERLAND	002
IA	IOWA PUBLIC SERVICE CO	MAYNARD	007
IA	IOWA STATE UNIVERSITY	CENTRAL HEATING	001
IA	IOWA STATE UNIVERSITY	CENTRAL HEATING	002
IA	IOWA STATE UNIVERSITY	CENTRAL HEATING	004
IA	IOWA STATE UNIVERSITY	CENTRAL HEATING	005
IA	IOWA-ILLINOIS GAS & ELEC	RIVERSIDE	004
IA	IOWA-ILLINOIS GAS & ELEC	RIVERSIDE	3HS
IA	MUSCATINE, CITY OF	MUSCATINE	005
IA	MUSCATINE, CITY OF	MUSCATINE	006
IA	MUSCATINE, CITY OF	MUSCATINE	007
IA	MUSCATINE, CITY OF	MUSCATINE	008
IA	PELLA MUNICIPAL POWER &	PELLA	003
IA	PELLA MUNICIPAL POWER &	PELLA	006
IA	UNIVERSITY OF IOWA	UNIVERSITY OF I	001
IA	UNIVERSITY OF IOWA	UNIVERSITY OF I	005
IA	UNIVERSITY OF IOWA	UNIVERSITY OF I	006
** STATE IL			
IL	CENT ILL PUB SERVICE COM	MEREDOSIA	001
IL	CENT ILL PUB SERVICE COM	MEREDOSIA	002
IL	ILLINOIS POWER COMPANY	VERMILION	001
IL	ROCHELLE MUNICIPAL UTIL	ROCHELLE 1	0S1
IL	SOUTHERN ILLINOIS POWER	MARION	001
IL	SOUTHERN ILLINOIS POWER	MARION	002
IL	SOUTHERN ILLINOIS POWER	MARION	003
IL	SPRINGFIELD, CITY OF (IL	LAKESIDE	006
IL	SPRINGFIELD, CITY OF (IL	LAKESIDE	007
IL	WESTERN ILLINOIS PWR COO	PEARL STATION	001
** STATE IN			
IN	CRAWFORDSVILLE MUNICIPAL	CRAWFORDSVILLE	004
IN	CRAWFORDSVILLE MUNICIPAL	CRAWFORDSVILLE	005
IN	INDIANAPOLIS PWR & LT CO	K. PERRY	005
IN	INDIANAPOLIS PWR & LT CO	K. PERRY	006
IN	INDIANAPOLIS PWR & LT CO	K. PERRY	007
IN	INDIANAPOLIS PWR & LT CO	PRITCHARD, H T	003
IN	INDIANAPOLIS PWR & LT CO	PRITCHARD, H T	004
IN	INDIANAPOLIS PWR & LT CO	PRITCHARD, H T	005
IN	JASPER MUNICIPAL ELEC UT	JASPER 2	001
IN	LOGANSPORT ELEC LT & PWR	LOGANSPORT	004
IN	LOGANSPORT ELEC LT & PWR	LOGANSPORT	005
IN	NORTHERN INDIANA PUBLIC	MICHIGAN CITY	002
IN	NORTHERN INDIANA PUBLIC	MICHIGAN CITY	003
IN	PERU, CITY OF LT & PWR D	PERU	001
IN	PERU, CITY OF LT & PWR D	PERU	003
IN	PUBLIC SERVICE CO OF IND	EDWARDSPORT	006
IN	PUBLIC SERVICE CO OF IND	EDWARDSPORT	007
IN	PUBLIC SERVICE CO OF IND	EDWARDSPORT	008
IN	PUBLIC SERVICE CO OF IND	EDWARDSPORT	066
IN	PUBLIC SERVICE CO OF IND	NOBLESVILLE	001
IN	PUBLIC SERVICE CO OF IND	NOBLESVILLE	002
IN	RICHMOND POWER & LIGHT (	WHITEWATER VALL	001
IN	RICHMOND POWER & LIGHT (	WHITEWATER VALL	002
IN	SOUTHERN INDIANA GAS & E	CULLEY	001
** STATE KS			
KS	EMPIRE DISTRICT ELECTRIC	RIVERTON	006
KS	EMPIRE DISTRICT ELECTRIC	RIVERTON	007
KS	KANSAS CITY BD OF PUB UT	KAW	001
KS	KANSAS CITY BD OF PUB UT	KAW	002
KS	KANSAS CITY BD OF PUB UT	KAW	003
** STATE KY			
KY	EAST KENTUCKY POWER COOP	DALE	001
KY	EAST KENTUCKY POWER COOP	DALE	002
KY	EAST KENTUCKY POWER COOP	DALE	003
KY	EAST KENTUCKY POWER COOP	DALE	004
KY	HENDERSON MUNIC PWR & LT	HENDERSON	005
KY	HENDERSON MUNIC PWR & LT	HENDERSON	006
KY	KENTUCKY UTILITIES COMPA	PINEVILLE	003

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LITTLE DIRTIES

	UTILITY	PLANT	UNIT
** STATE MA			
MA	EAST UTIL:MONTAUP ELECTR	SOMERSET	001
MA	EAST UTIL:MONTAUP ELECTR	SOMERSET	002
MA	EAST UTIL:MONTAUP ELECTR	SOMERSET	004
MA	TAUNTON MUN LIGHTING PLA	CLEARY, B F	008
** STATE MD			
MD	APS:POTOMAC EDISON CO	SMITH, R P	003
MD	BALTIMORE GAS & ELECTRIC	RIVERSIDE	003
** STATE ME			
ME	BANGOR HYDRO ELECTRIC CO	GRAHAM STATION	003
ME	BANGOR HYDRO ELECTRIC CO	GRAHAM STATION	004
ME	BANGOR HYDRO ELECTRIC CO	GRAHAM STATION	005
ME	CENTRAL MAINE POWER COMP	WYMAN, W F	001
ME	CENTRAL MAINE POWER COMP	WYMAN, W F	002
** STATE MI			
MI	COLDWATER PUBLIC WORKS	COLDWATER	004
MI	COLDWATER PUBLIC WORKS	COLDWATER	005
MI	COLDWATER PUBLIC WORKS	COLDWATER	006
MI	CONSUMERS POWER COMPANY	COBB, B C	001
MI	CONSUMERS POWER COMPANY	COBB, B C	002
MI	CONSUMERS POWER COMPANY	COBB, B C	003
MI	DETROIT EDISON COMPANY,	MARYSVILLE	006
MI	DETROIT EDISON COMPANY,	PORT HURON	002
MI	DETROIT EDISON COMPANY,	PORT HURON	003
MI	GRAND HAVEN BD OF LT & P	SIMS	001
MI	GRAND HAVEN BD OF LT & P	SIMS	002
MI	HOLLAND BOARD OF PUBLIC	JAMES DE YOUNG	003
MI	HOLLAND BOARD OF PUBLIC	JAMES DE YOUNG	004
MI	HOLLAND BOARD OF PUBLIC	JAMES DE YOUNG	005
MI	MARQUETTE, CITY OF BD OF	SHIRAS	001
MI	MARQUETTE, CITY OF BD OF	SHIRAS	002
MI	TRAVERSE, CITY OF EL LT	BAYSIDE	001
MI	TRAVERSE, CITY OF EL LT	BAYSIDE	002
MI	TRAVERSE, CITY OF EL LT	BAYSIDE	004
MI	WISC ELEC:UPPER PEN GENE	ESCANABA	001
MI	WISC ELEC:UPPER PEN GENE	ESCANABA	002
MI	WISC ELEC:UPPER PEN GENE	PRESQUE ISLE	003
MI	WISC ELEC:UPPER PEN GENE	PRESQUE ISLE	004
MI	WYANDOTTE DEPT OF MUN SE	WYANDOTTE	004
** STATE MN			
MN	AUSTIN UTILITIES (MN)	NORTHEAST STATI	001
MN	HIBBING PUBLIC UTILITIES	HIBBING	003
MN	HIBBING PUBLIC UTILITIES	HIBBING	005
MN	MINNESOTA POWER & LIGHT	SYL LASKIN (AUR	001
MN	MINNESOTA POWER & LIGHT	SYL LASKIN (AUR	002
MN	NEW ULM PUB UTILITIES CO	NEW ULM	002
MN	NEW ULM PUB UTILITIES CO	NEW ULM	003
MN	NEW ULM PUB UTILITIES CO	NEW ULM	004
MN	NORTHERN STATES POWER CO	HIGH BRIDGE	003
MN	NORTHERN STATES POWER CO	HIGH BRIDGE	004
MN	NORTHERN STATES POWER CO	MINNESOTA VALLE	003
MN	OTTER TAIL POWER COMPANY	HOOT LAKE	001
MN	OTTER TAIL POWER COMPANY	HOOT LAKE	002
MN	ROCHESTER, CITY OF ELEC	SILVER LAKE	001
MN	ROCHESTER, CITY OF ELEC	SILVER LAKE	002
MN	ROCHESTER, CITY OF ELEC	SILVER LAKE	003
MN	ROCHESTER, CITY OF ELEC	SILVER LAKE	004
MN	SLEEPY EYE PUBLIC UTIL C	SLEEPY EYE	002
MN	SLEEPY EYE PUBLIC UTIL C	SLEEPY EYE	004
MN	VIRGINIA PUBLIC UTILITIE	VIRGINIA	001
MN	VIRGINIA PUBLIC UTILITIE	VIRGINIA	004
MN	VIRGINIA PUBLIC UTILITIE	VIRGINIA	005
MN	VIRGINIA PUBLIC UTILITIE	VIRGINIA	006
MN	WILLMAR MUNICIPAL UTIL C	WILLMAR	003
MN	WILLMAR MUNICIPAL UTIL C	WILLMAR	004
MN	WILLMAR MUNICIPAL UTIL C	WILLMAR	005

LITTLE DIRTIES

	UTILITY	PLANT	UNIT
** STATE MO			
MO	CENTRAL ELECTRIC POWER C	CHAMOIS	001
MO	CENTRAL ELECTRIC POWER C	CHAMOIS	002
MO	CHILLICOTHE MUNICIPAL UT	CHILLICOTHE	003
MO	CHILLICOTHE MUNICIPAL UT	CHILLICOTHE	005
MO	CHILLICOTHE MUNICIPAL UT	CHILLICOTHE	006
MO	COLUMBIA WATER & LIGHT D	COLUMBIA	004
MO	COLUMBIA WATER & LIGHT D	COLUMBIA	005
MO	COLUMBIA WATER & LIGHT D	COLUMBIA	007
MO	COLUMBIA WATER & LIGHT D	COLUMBIA	008
MO	INDEPENDENCE, CITY OF (M	BLUE VALLEY	001
MO	INDEPENDENCE, CITY OF (M	BLUE VALLEY	002
MO	INDEPENDENCE, CITY OF (M	BLUE VALLEY	003
MO	KANSAS CITY POWER & LIGH	GRAND AVENUE	001
MO	KANSAS CITY POWER & LIGH	HAWTHORN	001
MO	KANSAS CITY POWER & LIGH	HAWTHORN	002
MO	MARSHALL MUNI (MO)	MARSHALL	002
MO	MARSHALL MUNI (MO)	MARSHALL	004
MO	SPRINGFIELD UTILITIES (M	JAMES RIVER	003
MO	SPRINGFIELD UTILITIES (M	JAMES RIVER	004
MO	UTILICORP	SIBLEY	001
MO	UTILICORP	SIBLEY	002
** STATE MS			
MS	GREENWOOD UTILITIES COMM	HENDERSON	001
MS	GREENWOOD UTILITIES COMM	HENDERSON	003
MS	SO CO:MISS PWR COMPANY	EATON	001
MS	SO CO:MISS PWR COMPANY	EATON	002
MS	SO CO:MISS PWR COMPANY	EATON	003
** STATE NC			
NC	CAROLINA POWER & LIGHT C	WEATHERSPOON	001
NC	CAROLINA POWER & LIGHT C	WEATHERSPOON	002
NC	CAROLINA POWER & LIGHT C	WEATHERSPOON	003
NC	DUKE POWER COMPANY	CLIFFSIDE	003
NC	DUKE POWER COMPANY	CLIFFSIDE	004
NC	DUKE POWER COMPANY	DAN RIVER	001
NC	DUKE POWER COMPANY	DAN RIVER	002
** STATE ND			
ND	MONTANA-DAKOTA UTILITIES	HESKETT	001
** STATE NH			
NH	PUBLIC SERVICE CO OF NH	SCHILLER	003
NH	PUBLIC SERVICE CO OF NH	SCHILLER	005
NH	PUBLIC SERVICE CO OF NH	SCHILLER	006
** STATE NJ			
NJ	ATLANTIC CITY:DEEPWATER	DEEPWATER	005
NJ	ATLANTIC CITY:DEEPWATER	DEEPWATER	007
** STATE NY			
NY	JAMESTOWN BOARD OF PUB U	CARLSON	005
NY	JAMESTOWN BOARD OF PUB U	CARLSON	006
NY	NEW YORK STATE ELEC & GA	GOUDEY	007
NY	NEW YORK STATE ELEC & GA	GREENIDGE	001
NY	NEW YORK STATE ELEC & GA	GREENIDGE	002
NY	NEW YORK STATE ELEC & GA	GREENIDGE	003
NY	NEW YORK STATE ELEC & GA	HICKLING	001
NY	NEW YORK STATE ELEC & GA	HICKLING	002
NY	NEW YORK STATE ELEC & GA	JENNISON	001
NY	NEW YORK STATE ELEC & GA	JENNISON	002
NY	ROCHESTER GAS & ELEC COR	STATION #3	006
NY	ROCHESTER GAS & ELEC COR	STATION #3	010
NY	ROCHESTER GAS & ELEC COR	STATION #3	011
NY	ROCHESTER GAS & ELEC COR	STATION #7	001
NY	ROCHESTER GAS & ELEC COR	STATION #7	002
NY	ROCHESTER GAS & ELEC COR	STATION #7	003
** STATE OH			
OH	AEP:COLUMBUS SOUTHERN PO	POSTON	002
OH	AEP:COLUMBUS SOUTHERN PO	POSTON	003

LITTLE DIRTIES

	UTILITY	PLANT	UNIT
OH	CENTER EN:CLEVELAND ELEC	ASHTABULA	006
OH	CENTER EN:CLEVELAND ELEC	ASHTABULA	007
OH	CENTER EN:CLEVELAND ELEC	ASHTABULA	008
OH	CENTER EN:CLEVELAND ELEC	ASHTABULA	009
OH	DOVER ELEC LT & POWER PL	DOVER	002
OH	DOVER ELEC LT & POWER PL	DOVER	003
OH	DOVER ELEC LT & POWER PL	DOVER	004
OH	OHIO EDISON COMPANY	BURGER, R E	001
OH	OHIO EDISON COMPANY	BURGER, R E	002
OH	OHIO EDISON COMPANY	EDGEWATER	002
OH	OHIO EDISON COMPANY	EDGEWATER	003
OH	OHIO EDISON COMPANY	GORGE STEAM	006
OH	OHIO EDISON COMPANY	GORGE STEAM	007
OH	OHIO EDISON COMPANY	TORONTO	005
OH	OHIO EDISON COMPANY	TORONTO	006
OH	OHIO EDISON COMPANY	TORONTO	007
OH	ORRVILLE MUN UTILITIES	VINE ST. (ORRVI	007
OH	ORRVILLE MUN UTILITIES	VINE ST. (ORRVI	008
OH	ORRVILLE MUN UTILITIES	VINE ST. (ORRVI	009
OH	ORRVILLE MUN UTILITIES	VINE ST. (ORRVI	010
OH	ORRVILLE MUN UTILITIES	VINE ST. (ORRVI	011
OH	PAINESVILLE MUN LT PLANT	PAINESVILLE	001
OH	PAINESVILLE MUN LT PLANT	PAINESVILLE	002
OH	PAINESVILLE MUN LT PLANT	PAINESVILLE	003
OH	PAINESVILLE MUN LT PLANT	PAINESVILLE	005
OH	PAINESVILLE MUN LT PLANT	PAINESVILLE	006
OH	PIQUA MUNICIPAL POWER SY	PIQUA	004
OH	PIQUA MUNICIPAL POWER SY	PIQUA	005
OH	PIQUA MUNICIPAL POWER SY	PIQUA	006
OH	PIQUA MUNICIPAL POWER SY	PIQUA	007
OH	SHELBY MUN LIGHT PLANT	SHELBY	001
OH	SHELBY MUN LIGHT PLANT	SHELBY	002
OH	SHELBY MUN LIGHT PLANT	SHELBY	003
OH	SHELBY MUN LIGHT PLANT	SHELBY	004
OH	ST MARYS MUN LT & PWR PL	ST. MARY'S	004
OH	ST MARYS MUN LT & PWR PL	ST. MARY'S	005
OH	ST MARYS MUN LT & PWR PL	ST. MARY'S	006
** STATE PA			
PA	GPU:PENNSYLVANIA ELECTRI	FRONT STREET	001
PA	GPU:PENNSYLVANIA ELECTRI	FRONT STREET	002
PA	GPU:PENNSYLVANIA ELECTRI	FRONT STREET	004
PA	GPU:PENNSYLVANIA ELECTRI	FRONT STREET	005
PA	GPU:PENNSYLVANIA ELECTRI	SEWARD	004
PA	GPU:PENNSYLVANIA ELECTRI	WARREN	001
PA	GPU:PENNSYLVANIA ELECTRI	WARREN	002
PA	GPU:PENNSYLVANIA ELECTRI	WILLIAMSBURG	005
PA	OHIO ED:PENN POWER CO	NEW CASTLE	001
PA	OHIO ED:PENN POWER CO	NEW CASTLE	002
** STATE SC			
SC	SOUTH CAROLINA PUBLIC SE	JEFFERIES	002
** STATE SD			
SD	BLACK HILLS PWR & LT CO	KIRK	003
SD	BLACK HILLS PWR & LT CO	KIRK	004
** STATE VA			
VA	VIRGINIA ELECTRIC & POWE	BREMO BLUFF	003
** STATE VT			
VT	BURLINGTON ELECTRIC DEPT	MORAN	001
VT	BURLINGTON ELECTRIC DEPT	MORAN	002
VT	BURLINGTON ELECTRIC DEPT	MORAN	003
** STATE WI			
WI	DAIRYLAND POWER COOPERAT	ALMA	001
WI	DAIRYLAND POWER COOPERAT	ALMA	002
WI	DAIRYLAND POWER COOPERAT	ALMA	003
WI	DAIRYLAND POWER COOPERAT	ALMA	004
WI	DAIRYLAND POWER COOPERAT	STONEMAN	001
WI	DAIRYLAND POWER COOPERAT	STONEMAN	002

LITTLE DIRTIES

	UTILITY	PLANT	UNIT
WI	MADISON GAS & ELECTRIC C	BLOUNT STREET	005
WI	MADISON GAS & ELECTRIC C	BLOUNT STREET	006
WI	MADISON GAS & ELECTRIC C	BLOUNT STREET	007
WI	MANITOWOC PUBLIC UTILITI	MANITOWOC	003
WI	MANITOWOC PUBLIC UTILITI	MANITOWOC	004
WI	MANITOWOC PUBLIC UTILITI	MANITOWOC	005
WI	MANITOWOC PUBLIC UTILITI	MANITOWOC	006
WI	MARSHFIELD ELECTRIC & WA	WILDWOOD	004
WI	MARSHFIELD ELECTRIC & WA	WILDWOOD	005
WI	MENASHA ELECTRIC & WATER	MENASHA	001
WI	MENASHA ELECTRIC & WATER	MENASHA	002
WI	MENASHA ELECTRIC & WATER	MENASHA	003
WI	MENASHA ELECTRIC & WATER	MENASHA	004
WI	NORTHERN STA:LAKE SUPERI	BAYFRONT	004
WI	NORTHERN STA:LAKE SUPERI	BAYFRONT	005
WI	NORTHERN STA:LAKE SUPERI	BAYFRONT	006
WI	WISCONSIN POWER & LIGHT	BLACK HAWK	003
WI	WISCONSIN POWER & LIGHT	BLACK HAWK	004
WI	WISCONSIN POWER & LIGHT	EDGEWATER	003
WI	WISCONSIN PUBLIC SERVICE	PULLIAM	001
WI	WISCONSIN PUBLIC SERVICE	PULLIAM	002
WI	WISCONSIN PUBLIC SERVICE	PULLIAM	003
WI	WISCONSIN PUBLIC SERVICE	PULLIAM	004
WI	WISCONSIN PUBLIC SERVICE	WESTON	001
** STATE WV			
WV	APS:MONONGAHELA POWER CO	ALBRIGHT	002
WV	APS:MONONGAHELA POWER CO	RIVESVILLE	005
WV	APS:MONONGAHELA POWER CO	WILLOW ISLAND	001
WV	APS:POTOMAC EDISON CO	ALBRIGHT	001

ATTACHMENT 2

DATA ON SO_2 AND NO_X EMISSIONS

BY INDUSTRIAL CATEGORY

(A list of the category codes follows the data)

TABLE A - 22. 1985 NAPAP MODELER'S EMISSIONS INVENTORY VERSION 2 - U.S. POINT SOURCE EMISSIONS BY SCC

SCC	(TONS/YEAR) SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
101001	22,353	0	393	822	163	1	11,876	11,518	356
101002	14,801,381	122,099	218,483	629,939	76,256	186	5,603,549	5,635,442	168,106
101003	581,054	298	12,676	128	128	7	381,061	369,629	11,432
101004	593,369	11,493	16,185	0	0	2,553	169,062	160,609	8,653
101005	17,140	0	2,918	0	0	196	19,687	18,702	986
101006	3,092	0	55,566	0	0	5,703	418,636	397,704	20,932
101007	45	0	206	0	0	0	4,487	4,262	224
101008	6,032	0	66	0	0	0	2,327	2,257	70
101009	126	0	3,455	0	0	0	2,466	2,343	123
101010	0	0	1	0	0	0	5	5	0
101012	0	0	0	0	0	0	1,806	855	151
101013	6	0	0	0	0	0	2	2	0
102001	10,998	0	4,346	181	36	0	5,755	5,467	288
102002	1,272,847	32,993	60,297	68,667	5,865	15	433,631	411,950	21,682
102003	78,417	0	4,281	2	2	0	27,056	25,703	1,353
102004	398,823	9,723	23,259	0	0	2,010	135,619	128,838	6,781
102005	45,858	0	1,998	0	0	281	36,244	34,432	1,812
102006	34,970	0	46,076	0	0	7,381	271,701	258,116	13,505
102007	105,776	0	17,138	0	0	0	101,971	96,983	4,988
102008	11,911	0	298	0	0	0	6,764	6,561	203
102009	15,141	1,936	142,109	0	0	0	84,943	80,695	4,267
102010	27	0	848	0	0	0	628	597	31
102011	170	0	6,161	0	0	0	1,691	1,607	85
102012	2,753	0	622	0	0	0	3,720	3,162	558
102013	12,199	0	6,096	0	0	0	12,016	10,395	1,621
102014	8,513	0	1,743	0	0	0	2,501	2,452	129
103001	3,032	0	672	269	11	0	1,064	1,012	31
103002	113,933	0	9,234	2,693	309	1	23,119	22,426	694
103003	973	0	21	26	4	0	467	453	14
103004	42,373	0	1,665	0	0	178	16,102	15,297	805
103005	5,277	0	575	0	0	29	2,864	2,702	162
103006	725	0	1,965	0	0	23	14,263	13,550	713
103007	17	0	165	0	0	0	375	356	19
103009	80	0	10,409	0	0	0	2,765	2,627	138
103010	0	0	0	0	0	0	0	0	0
103012	300	0	1,105	0	0	0	1,085	922	163
103013	1	0	0	0	0	0	119	101	18
105001	610	0	1,759	0	0	214	2,764	2,626	138
105002	147	0	73	0	0	3	609	578	30
201001	3,222	0	2,056	0	0	0	9,473	8,058	615
201002	26,330	0	7,171	0	0	0	37,643	35,520	2,126
201009	28	0	207	0	0	0	751	713	38
202001	750	0	1,130	0	0	0	5,301	4,796	505
202002	5,937	0	106,795	0	0	0	644,053	610,861	33,191
202003	15	0	4,330	0	0	0	110	106	5
202004	120	0	385	0	0	0	2,012	1,912	101
202005	96	0	120	0	0	0	573	516	57
202009	421	0	46	0	0	0	205	195	10
202010	0	0	121	0	0	0	144	137	7
203001	1,691	0	218	0	0	0	3,455	3,109	365
203002	26	0	1,728	0	0	0	12,696	11,860	625
203003	184	0	15,279	0	0	0	1,576	1,497	79
203010	0	0	254	0	0	0	183	174	9
204001	205	0	2,962	0	0	0	1,940	1,843	97

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

	(TONS/YEAR)								
SCC	SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
204002	1	0	506	0	0	0	13	12	1
204003	22	0	409	0	0	0	1,368	1,286	82
204004	161	0	40,652	0	0	0	2,290	2,174	116
288888	215	0	457	0	0	0	1,389	1,320	69
301001	25	0	18,315	0	0	0	624	593	31
301003	1,096	0	11,329	0	0	8,360	24,351	23,134	1,218
301005	28,031	0	1,225,936	0	0	0	1,283	1,219	64
301006	4,643	0	37,882	0	0	0	3,648	3,105	543
301007	0	0	0	0	0	0	0	0	0
301008	19	0	2,357	0	0	0	2,223	2,112	111
301009	126	0	18	0	0	0	105	100	5
301010	12	0	1	0	0	0	1,705	1,619	86
301011	1,540	0	181	1,068	0	0	13	12	1
301012	391	0	5	0	0	0	47	45	2
301013	0	0	3,246	0	0	0	32,234	30,622	1,612
301014	0	0	0	0	0	0	54	51	3
301015	0	0	0	0	0	0	0	0	0
301016	3	0	3	0	3,489	0	22	21	1
301017	0	0	0	0	0	0	0	0	0
301018	1,081	0	2,119	0	0	0	18,061	17,158	903
301019	45	0	15,733	0	0	0	235	223	12
301020	0	0	0	0	0	0	0	0	0
301021	42	0	20	0	0	0	781	742	39
301022	2,091	0	0	0	0	0	1	1	0
301023	215,075	1,357	102	0	0	0	2,009	1,909	100
301024	141	0	53	0	0	0	7	7	0
301025	0	0	0	0	0	0	0	0	0
301026	4,663	0	16,223	0	0	0	1,701	1,616	85
301027	3	0	176	0	0	127,830	288	273	14
301028	255	0	0	0	0	0	65	62	3
301029	396	0	7	0	13,941	0	96	91	5
301030	1,554	0	10	0	1,489	571	1,252	1,190	63
301031	0	0	25,527	0	0	0	0	0	0
301032	128,706	0	1,257	0	0	0	16,346	15,529	817
301033	708	0	28	0	0	0	266	253	13
301034	126	0	817	0	0	0	805	765	40
301035	5,682	0	83,721	0	0	0	567	539	28
301038	0	0	0	0	0	0	0	0	0
301040	0	0	680	0	0	47,790	18	17	1
301041	13	0	0	0	0	0	36	34	2
301042	0	0	0	0	0	0	6	6	0
301045	0	0	0	0	0	0	0	0	0
301050	0	0	135	0	0	0	422	401	21
301060	217	0	19	0	0	0	24	23	1
301070	4	0	0	0	0	0	59	56	3
301091	1	0	9	0	0	0	0	0	0
301100	0	0	10,969	0	0	0	1	1	0
301111	0	0	0	0	0	0	0	0	0
301112	287	0	0	0	0	0	0	0	0
301120	0	0	2,113	0	0	0	0	0	0
301121	0	0	0	0	0	0	0	0	0
301125	3	0	147	0	0	0	675	641	34
301126	57	0	0	0	0	0	0	0	0
301127	0	0	0	0	0	0	0	0	0

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

SCC	SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
	(TONS/YEAR)								
301130	0	0	0	0	0	0	0	0	0
301132	108	0	668	0	0	0	530	503	26
301133	0	0	1,093	0	0	0	0	0	0
301137	486	0	26	0	0	0	6	6	0
301140	0	0	53	0	0	0	55	52	3
301152	0	0	0	0	0	0	0	0	0
301153	0	0	646	0	0	0	1,834	1,742	92
301157	0	0	0	0	0	0	3	3	0
301158	6	0	4,930	0	0	0	0	0	0
301167	0	0	0	0	0	0	0	0	0
301169	2	0	2	0	0	0	76	72	4
301174	0	0	120	0	0	0	598	568	30
301176	0	0	0	0	0	0	0	0	0
301181	2	0	21	0	0	0	3	3	0
301197	6,106	0	2,274	0	0	0	12,606	11,976	630
301202	0	0	7	0	0	0	148	141	7
301205	0	0	0	0	0	0	0	0	0
301206	1	0	3	0	0	0	29	28	1
301211	0	0	0	0	0	0	14	13	1
301250	963	0	1,594	0	0	0	3,126	2,969	156
301251	0	0	0	0	0	0	0	0	0
301252	0	0	0	0	0	0	0	0	0
301253	0	0	0	0	0	0	0	0	0
301254	3,201	0	10,151	0	0	0	1,846	1,754	92
301258	5	0	121	0	0	0	1,391	1,321	70
301304	0	0	0	0	0	0	0	0	0
301305	0	0	0	0	0	0	0	0	0
301800	1,945	0	131	0	0	0	537	510	27
301810	0	0	1,155	0	0	0	10	9	0
301820	0	0	0	0	0	0	0	0	0
301830	0	0	119	0	0	0	357	339	18
301840	0	0	1,110	0	0	0	0	0	0
301870	0	0	0	0	0	0	10	9	0
301875	0	0	0	0	0	0	0	0	0
301880	50	0	631	0	0	0	528	502	26
301900	44,201	0	1,204	0	0	0	10,470	9,946	523
301999	48,091	0	27,707	0	0	0	27,118	25,762	1,356
302001	6	0	0	0	0	0	6	6	0
302002	7	0	0	0	0	0	102	97	5
302003	0	0	0	0	0	0	0	0	0
302004	0	0	0	0	0	0	0	0	0
302005	0	0	1	0	0	0	0	0	0
302006	0	0	44	0	0	0	180	171	9
302007	114	0	5	0	0	0	89	85	4
302008	0	0	3	0	0	0	54	51	3
302009	303	0	15	0	0	0	113	107	6
302010	0	0	30	0	0	0	54	51	3
302013	42	0	38	0	0	0	29	28	1
302014	76	0	4	0	0	0	2,039	1,937	102
302015	5	0	0	0	0	0	11	10	1
302016	1,918	0	98	0	0	0	661	627	33
302017	0	0	0	0	0	0	3	3	0
302018	0	0	0	0	0	0	0	0	0
302019	41	0	3	0	0	0	34	32	2

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

SCC	SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
	(TONS/YEAR)								
302020	37	0	0	0	0	1,953	202	192	10
302030	0	0	2	0	0	0	12	11	1
302031	0	0	0	0	0	0	0	0	0
302032	1	0	0	0	0	0	0	0	0
302033	7	0	0	0	0	0	0	0	0
302036	0	0	0	0	0	0	0	0	0
302888	0	0	0	0	0	0	0	0	0
302999	810	0	18	0	0	0	1,192	1,132	60
303000	1	0	474	0	0	0	2,095	1,990	105
303001	46,232	230	495,430	0	6,515	0	965	917	48
303002	12,154	0	78	0	0	0	1,402	1,332	70
303003	73,829	8,958	13,725	0	0	5,893	11,735	11,149	587
303004	1,599	0	36	0	0	0	541	514	27
303005	655,324	0	7,201	0	0	0	1,039	987	52
303006	9,429	0	372	0	0	0	456	433	23
303007	587	0	0	0	0	0	0	0	0
303008	43,846	833	331,479	0	0	0	11,651	11,069	583
303009	26,707	0	826,870	0	0	0	19,044	18,092	952
303010	98,776	0	12,177	0	0	0	1,745	1,657	87
303011	986	0	0	0	0	0	4	4	0
303012	0	0	6,000	0	0	0	136	129	7
303013	0	0	0	0	0	0	0	0	0
303014	2,514	0	1,528	0	0	0	1,130	1,073	56
303023	1,547	0	0	0	0	0	1,468	1,396	73
303024	0	0	0	0	0	0	0	0	0
303030	7,441	0	0	0	0	0	4	4	0
303888	12,060	0	15	0	0	0	93	88	5
303900	1,985	0	5,558	0	0	0	363	345	18
303999	579	0	193	0	0	0	476	452	24
304001	3,768	0	182	0	0	0	3,636	3,454	182
304002	8	0	445	0	0	0	79	75	4
304003	2,527	0	143,432	0	0	0	1,039	987	52
304004	20,721	0	26	0	0	0	907	862	45
304005	1,347	0	247	0	0	0	990	940	49
304006	27	0	6,172	0	0	0	538	511	27
304007	13,540	0	11,607	0	0	0	7,579	7,200	379
304008	3,094	0	5	0	0	0	195	185	10
304009	0	0	2,696	0	0	0	32	30	2
304010	0	0	5	0	0	0	11	10	1
304020	3,979	0	5,450	0	0	0	298	283	15
304022	0	0	0	0	0	0	0	0	0
304050	0	0	5	0	0	0	82	78	4
304888	0	0	0	0	0	0	0	0	0
304900	33	0	5	0	0	0	4,165	3,957	208
304999	971	0	118	0	0	0	571	542	29
305001	74	0	582	0	0	0	135	128	7
305002	1,959	0	312	0	0	0	861	818	43
305003	2,193	0	976	0	0	0	791	751	40
305004	199	0	45	0	0	0	2	2	0
305005	149	0	86	0	0	0	721	685	36
305006	112,500	11,802	6,303	0	0	0	98,212	93,301	4,911
305007	79,305	553	1,836	0	0	0	38,963	37,014	1,948
305008	2,362	0	165	0	0	0	1,172	1,113	59
305009	1,389	0	5	0	0	0	371	352	19

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

SCC	SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
	(TONS/YEAR)								
305010	12,481	0	5,222	0	0	0	5,004	4,754	250
305011	0	0	0	0	0	0	0	0	0
305012	2,487	0	1,921	0	0	0	6,210	5,899	310
305014	21,440	0	2,259	0	0	0	47,453	45,081	2,373
305015	9,396	768	55	0	0	0	1,826	1,735	91
305016	26,567	0	22,332	0	0	0	28,828	27,387	1,441
305017	9	0	50	0	0	0	58	55	3
305018	496	0	67	0	0	0	1,150	1,100	58
305019	4,651	0	54	0	0	0	1,145	1,088	57
305020	6,198	0	31	0	0	0	763	725	38
305021	0	0	4	0	0	0	4	4	0
305022	0	0	0	0	0	0	0	0	0
305024	253	0	88	0	0	0	51	48	3
305025	0	0	3	0	0	0	35	33	2
305026	1	0	30	0	0	0	111	105	6
305030	0	0	0	0	0	0	0	0	0
305031	0	0	0	0	0	0	0	0	0
305032	5	0	0	0	0	0	5	5	0
305040	338	0	49	0	0	0	551	523	28
305100	0	0	0	0	0	0	0	0	0
305101	0	0	0	0	0	0	0	0	0
305102	0	0	0	0	0	0	0	0	0
305103	0	0	0	0	0	0	0	0	0
305104	0	0	0	0	0	0	0	0	0
305105	0	0	0	0	0	0	0	0	0
305150	308	0	64	0	0	0	111	105	6
305800	0	0	1	0	0	0	2	2	0
305900	134	0	7	0	0	0	53	50	3
305999	5,676	0	332	0	0	0	5,269	5,006	263
306001	163,144	0	21,357	0	0	0	155,933	148,136	7,797
306002	204,974	13,177	380,309	0	0	42,793	40,036	34,075	5,961
306003	7,273	0	14,710	0	0	52	1,209	1,027	181
306004	15,737	0	5,478	0	0	0	4,399	4,179	220
306005	1,080	0	534	0	0	0	123	117	6
306006	110	0	35	0	0	0	296	281	15
306007	0	0	25	0	0	0	376	357	19
306008	12,311	0	29	0	0	0	221	210	11
306009	28,980	0	3,889	0	0	0	3,809	3,606	196
306010	135	0	0	0	0	0	0	0	0
306011	91	0	1,282	0	0	0	0	0	0
306012	26,920	0	1,737	0	0	0	2,235	2,123	112
306014	12,560	0	2	0	0	0	1,083	1,029	54
306099	29,318	0	1,337	0	0	0	152	144	8
306100	0	0	0	0	0	0	1	1	0
306800	1,738	0	1,240	0	0	0	2,004	1,900	106
306999	17,097	0	308	0	0	0	2,836	2,694	142
307001	122,723	46,563	622,210	0	0	0	71,222	67,461	3,561
307002	6,609	106	1,959	0	0	0	162	154	8
307003	975	0	18	0	0	0	132	126	7
307004	3	0	2	0	0	0	11	10	1
307005	0	0	60	0	0	0	6	6	0
307007	144	0	1,090	0	0	0	779	740	39
307008	16	0	791	0	0	0	771	732	39
307011	0	0	0	0	0	0	79	75	4

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

SCC	SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
	(TONS/YEAR)								
307013	13	0	4	0	0	0	3	0	0
307020	39	0	0	0	0	0	3	3	0
307030	1	0	0	0	0	0	0	0	0
307888	0	0	7	0	0	0	38	36	2
307900	52	0	186	0	0	0	246	234	12
307999	25	0	822	0	0	0	127	121	6
308001	5	0	67	0	0	0	35	33	2
308006	0	0	1	0	0	0	0	0	0
308007	767	0	0	0	0	0	4	4	0
308999	1	0	0	0	0	0	0	0	0
309001	0	0	6	0	0	0	48	46	2
309002	0	0	0	0	0	0	0	0	0
309003	0	0	0	0	0	0	0	0	0
309010	0	0	0	0	0	0	5	5	0
309011	66	0	0	0	0	0	1,442	1,370	72
309016	0	0	0	0	0	0	0	0	0
3090[illegible]	0	0	0	0	0	0	0	0	0
309030	0	0	0	0	0	0	0	0	0
309040	0	0	0	0	0	0	0	0	0
309060	0	0	0	0	0	0	0	0	0
309888	0	0	1	0	0	0	5	5	0
309999	192	0	79	0	0	0	212	202	11
310001	1,840	0	254	0	0	0	19	18	1
310002	266,911	0	12,966	0	0	0	69,031	65,579	3,452
310004	1,078	0	620	0	0	0	3,871	3,677	194
310888	34	0	25	0	0	0	25	24	1
312999	1	0	0	0	0	0	0	0	0
313070	0	0	0	0	0	0	0	0	0
313999	663	0	17,019	0	0	0	0	0	0
314010	0	0	6	0	0	0	0	0	0
314011	0	0	0	0	0	0	0	0	0
314999	0	0	1	0	0	0	0	0	0
315020	0	0	0	0	0	0	0	0	0
320999	1	0	0	0	0	0	0	0	0
330001	0	0	5	0	0	0	61	58	3
330002	0	0	0	0	0	0	0	0	0
330003	0	0	0	0	0	0	0	0	0
330888	0	0	0	0	0	0	0	0	0
390001	177	0	1	0	0	0	0	0	0
390002	101,997	0	71	0	0	0	9,757	9,395	362
390003	72	0	3	0	0	0	69	67	2
390004	25,406	0	392	0	0	0	5,551	5,273	278
390005	5,926	0	1,365	0	0	0	2,561	2,433	128
390006	13,693	0	9,657	0	0	0	29,019	27,568	1,451
390007	9,954	0	1,420	0	0	0	4,157	3,976	183
390008	9,656	0	2,352	0	0	0	3,239	3,141	98
390009	3	0	247	0	0	0	157	150	8
390010	5	0	10	0	0	0	58	55	3
390012	0	0	25	0	0	0	33	31	2
390013	166	0	11	0	0	0	0	0	0
399900	452	0	51	0	0	0	666	632	33
399999	717	0	3,032	0	0	0	1,782	1,693	89
401001	0	0	0	0	0	0	0	0	0
401002	28	0	1,047	0	0	0	42	40	2

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

	(TONS/YEAR)								
SCC	SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
401003	0	0	0	0	0	0	0	0	0
401004	0	0	0	0	0	0	0	0	0
401888	0	0	0	0	0	0	0	0	0
402001	0	0	3	0	0	0	83	79	4
402002	0	0	0	0	0	0	0	0	0
402003	30	0	0	0	0	0	0	0	0
402004	0	0	0	0	0	0	0	0	0
402005	0	0	0	0	0	0	1	1	0
402006	0	0	0	0	0	0	7	7	0
402007	0	0	0	0	0	0	1	1	0
402008	789	0	202	0	0	0	2,015	1,915	101
402009	0	0	0	0	0	0	0	0	0
402010	26	0	42	0	0	0	5,763	5,475	288
402011	0	0	0	0	0	0	0	0	0
402013	0	0	0	0	0	0	1	1	0
402014	0	0	1	0	0	0	7	7	0
402015	0	0	0	0	0	0	0	0	0
402016	0	0	0	0	0	0	4	4	0
402017	0	0	30	0	0	0	12	11	1
402018	0	0	1	0	0	0	3	3	0
402019	0	0	0	0	0	0	0	0	0
402020	0	0	0	0	0	0	0	0	0
402021	30	0	0	0	0	0	0	0	0
402022	0	0	0	0	0	0	0	0	0
402023	0	0	0	0	0	0	0	0	0
402024	0	0	39	0	0	0	0	0	0
402025	0	0	0	0	0	0	2	2	0
402888	0	0	0	0	0	0	0	0	0
402999	0	0	0	0	0	0	7	7	0
403001	4	0	306	0	0	0	4	4	0
403002	166	0	0	0	0	0	0	0	0
403003	0	0	0	0	0	0	0	0	0
403010	0	0	0	0	0	0	898	853	45
403011	117	0	1	0	0	0	15	14	1
403012	3	0	0	0	0	0	0	0	0
403888	0	0	1	0	0	0	5	5	0
403999	0	0	0	0	0	0	0	0	0
404001	0	0	24	0	0	0	0	0	0
404002	0	0	0	0	0	0	0	0	0
404003	0	0	0	0	0	0	0	0	0
404004	0	0	0	0	0	0	0	0	0
405001	0	0	137	0	0	0	83	79	4
405002	0	0	0	0	0	0	7	7	0
405003	0	0	14	0	0	0	132	125	7
405004	0	0	0	0	0	0	18	9	0
405005	3	0	5	0	0	0	20	19	1
405006	0	0	0	0	0	0	0	0	0
405007	0	0	0	0	0	0	0	0	0
405888	0	0	0	0	0	0	9	9	0
406001	0	0	126	0	0	0	4	4	0
406002	245	0	2	0	0	0	98	93	5
406003	0	0	0	0	0	0	0	0	0
406004	0	0	0	0	0	0	0	0	0
406888	961	0	21	0	0	0	33	31	2

NOTE: 1 METRIC TON = 1.10231707 TONS

TABLE A - 22. (continued)

SCC	(TONS/YEAR) SO2	SO4	CO	HCL	HF	NH3	NOX	NO	NO2
407004	0	0	0	0	0	0	0	0	0
407008	0	0	0	0	0	0	0	0	0
407016	0	0	0	0	0	0	0	0	0
407020	0	0	0	0	0	0	0	0	0
407032	0	0	0	0	0	0	0	0	0
407036	0	0	0	0	0	0	0	0	0
407040	0	0	0	0	0	0	0	0	0
407044	0	0	0	0	0	0	0	0	0
407060	0	0	0	0	0	0	0	0	0
407068	0	0	0	0	0	0	0	0	0
407076	0	0	0	0	0	0	0	0	0
407084	0	0	0	0	0	0	0	0	0
407172	0	0	0	0	0	0	0	0	0
407180	0	0	0	0	0	0	0	0	0
407200	0	0	0	0	0	0	0	0	0
407220	0	0	0	0	0	0	0	0	0
407228	0	0	0	0	0	0	0	0	0
407816	0	0	42	0	0	0	141	134	7
407820	0	0	0	0	0	0	0	0	0
407860	0	0	0	0	0	0	0	0	0
407999	0	0	0	0	0	0	0	0	0
408999	0	0	0	0	0	0	0	0	0
490001	0	0	0	0	0	0	0	0	0
490002	0	0	0	0	0	0	0	0	0
490000	0	0	0	0	0	0	0	0	0
490999	52	0	10	0	0	0	15	14	1
501001	5,509	0	32,090	7,683	0	0	6,422	5,459	963
501002	0	0	153	0	0	0	429	366	66
501005	115	0	2,733	0	0	0	706	651	115
501007	0	0	0	0	0	0	0	0	0
502001	3,359	0	12,291	0	0	0	4,140	3,596	543
502002	0	0	10	0	0	0	0	0	0
502003	1	0	35	0	0	0	5	4	1
502005	88	0	36	0	0	0	1,115	948	167
502006	105	0	203	0	0	0	126	120	6
503001	8,077	0	19,336	1,294	0	0	3,880	3,289	511
503002	1	0	623	0	0	0	96	81	16
503005	476	0	67	0	0	0	329	280	49
503006	155	0	154	0	0	0	80	76	6
503007	444	0	2	133	0	0	43	41	2
503008	0	0	0	0	0	0	0	0	0
503900	735	0	273	0	0	0	473	449	26
TOTAL	21,180,139	262,865	5,461,174	602,606	108,408	254,019	9,466,962	9,105,060	361,912

NOTE: 1 METRIC TON = 1.10231707 TONS

APPENDIX B

LISTING OF SOURCE CLASSIFICATION CODES FOR U.S. AND CANADIAN POINT AND AREA SOURCES

TABLE B-1. SIX-DIGIT POINT SOURCE CLASSIFICATION CODES INCLUDED IN THE 1985 U.S. AND CANADIAN MAPAP INVENTORIES.

SCC	SOURCE DESCRIPTION/PROCESS		
101001	EXTCOMB BOILER	ELECTRIC GENERATN	ANTHRACITE COAL
101002	EXTCOMB BOILER	ELECTRIC GENERATN	BITUMINOUS COAL
101003	EXTCOMB BOILER	ELECTRIC GENERATN	LIGNITE
101004	EXTCOMB BOILER	ELECTRIC GENERATN	RESIDUAL OIL
101005	EXTCOMB BOILER	ELECTRIC GENERATN	DISTILLATE OIL
101006	EXTCOMB BOILER	ELECTRIC GENERATN	NATURAL GAS
101007	EXTCOMB BOILER	ELECTRIC GENERATN	PROCESS GAS
101008	EXTCOMB BOILER	ELECTRIC GENERATN	COKE
101009	EXTCOMB BOILER	ELECTRIC GENERATN	WOOD/BARK WASTE
101010	EXTCOMB BOILER	ELECTRIC GENERATN	LIQ PETROLEUM GAS
101011	EXTCOMB BOILER	ELECTRIC GENERATN	BAGASSE
101012	EXTCOMB BOILER	ELECTRIC GENERATN	SLD WASTE-SPECIFY
101013	EXTCOMB BOILER	ELECTRIC GENERATN	LIQ WASTE-SPECIFY
102001	EXTCOMB BOILER	INDUSTRIAL	ANTHRACITE COAL
102002	EXTCOMB BOILER	INDUSTRIAL	BITUMINOUS COAL
102003	EXTCOMB BOILER	INDUSTRIAL	LIGNITE
102004	EXTCOMB BOILER	INDUSTRIAL	RESIDUAL OIL
102005	EXTCOMB BOILER	INDUSTRIAL	DISTILLATE OIL
102006	EXTCOMB BOILER	INDUSTRIAL	NATURAL GAS
102007	EXTCOMB BOILER	INDUSTRIAL	PROCESS GAS
102008	EXTCOMB BOILER	INDUSTRIAL	COKE
102009	EXTCOMB BOILER	INDUSTRIAL	WOOD/BARK WASTE
102010	EXTCOMB BOILER	INDUSTRIAL	LIQ PETROLEUM GAS
102011	EXTCOMB BOILER	INDUSTRIAL	BAGASSE
102012	EXTCOMB BOILER	INDUSTRIAL	SLD WASTE-SPECIFY
102013	EXTCOMB BOILER	INDUSTRIAL	LIQ WASTE-SPECIFY
102014	EXTCOMB BOILER	INDUSTRIAL	CO BOILER
103001	EXTCOMB BOILER	COMMERCL-INSTUTNL	ANTHRACITE COAL
103002	EXTCOMB BOILER	COMMERCL-INSTUTNL	BITUMINOUS COAL
103003	EXTCOMB BOILER	COMMERCL-INSTUTNL	LIGNITE
103004	EXTCOMB BOILER	COMMERCL-INSTUTNL	RESIDUAL OIL
103005	EXTCOMB BOILER	COMMERCL-INSTUTNL	DISTILLATE OIL
103006	EXTCOMB BOILER	COMMERCL-INSTUTNL	NATURAL GAS
103007	EXTCOMB BOILER	COMMERCL-INSTUTNL	PROCESS GAS
103009	EXTCOMB BOILER	COMMERCL-INSTUTNL	WOOD/BARK WASTE
103010	EXTCOMB BOILER	COMMERCL-INSTUTNL	LIQ PETROLEUM GAS
103012	EXTCOMB BOILER	COMMERCL-INSTUTNL	SLD WASTE-SPECIFY
103013	EXTCOMB BOILER	COMMERCL-INSTUTNL	LIQ WASTE-SPECIFY
105001	EXTCOMB BOILER	SPACE HEATER	INDUSTRIAL
105002	EXTCOMB BOILER	SPACE HEATER	COMMERCL-INSTUTNL
201001	INTERNLCOMBUSTION	ELECTRIC GENERATN	DIST.OIL/DIESEL
201007	INTERNLCOMBUSTION	ELECTRIC GENERATN	PROCESS GAS
201008	INTERNLCOMBUSTION	ELECTRIC GENERATN	LANDFILL GAS
201002	INTERNLCOMBUSTION	ELECTRIC GENERATN	NATURAL GAS
201009	INTERNLCOMBUSTION	ELECTRIC GENERATN	KERONAPTHA JET FL
201010	INTERNLCOMBUSTION	ELECTRIC GENERATN	GEYSERS/GEOTHERML
202001	INTERNLCOMBUSTION	INDUSTRIAL	DIST.OIL/DIESEL
202002	INTERNLCOMBUSTION	INDUSTRIAL	NATURAL GAS

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
202003	INTERNLCOMBUSTION	INDUSTRIAL	GASOLINE
202004	INTERNLCOMBUSTION	INDUSTRIAL	LARGE BORE ENGINE
202005	INTERNLCOMBUSTION	INDUSTRIAL	RESIDUAL/CRUDEOIL
202009	INTERNLCOMBUSTION	INDUSTRIAL	KERONAPTHA JET FL
202010	INTERNLCOMBUSTION	INDUSTRIAL	PROPANE/BUTANE
203001	INTERNLCOMBUSTION	COMMERCL-INSTUTNL	DIST.OIL/DIESEL
203002	INTERNLCOMBUSTION	COMMERCL-INSTUTNL	NATURAL GAS
203003	INTERNLCOMBUSTION	COMMERCL-INSTUTNL	GASOLINE
203010	INTERNLCOMBUSTION	COMMERCL-INSTUTNL	PROPANE/BUTANE
204001	INTERNLCOMBUSTION	ENGINE TESTING	AIRCRAFT
204002	INTERNLCOMBUSTION	ENGINE TESTING	ROCKET MOTOR
204003	INTERNLCOMBUSTION	ENGINE TESTING	TURBINE
204004	INTERNLCOMBUSTION	ENGINE TESTING	RECIPROCATING
288888	INTERNLCOMBUSTION	FUGITIVE EMISSION	NOT CLASSIFIED
301001	CHEMICAL MFG	ORGANIC CHEMICALS	ADIPIC ACID PROD
301003	CHEMICAL MFG	AGRICULTURAL CHEM	AMMONIA
301005	CHEMICAL MFG	CARBON BLACK	
301006	CHEMICAL MFG	ORGANIC CHEMICALS	CHARCOAL
301007	CHEMICAL MFG	INORGANIC CHEMCLS	CHLORINE
301008	CHEMICAL MFG	INORGANIC CHEMCLS	CHLORO-ALKALI
301009	CHEMICAL MFG	SOAP/DETERGENTS	SOAP/DETERGENTS/CLEANRS
301010	CHEMICAL MFG	EXPLOSIVES	TRINITROTOLUENE
301011	CHEMICAL MFG	INORGANIC CHEMCLS	HYDROCHLORIC ACID
301012	CHEMICAL MFG	INORGANIC CHEMCLS	HYDROFLUORIC ACID
301013	CHEMICAL MFG	AGRICULTURAL CHEM	NITRIC ACID
301014	CHEMICAL MFG	PAINT MFG	
301015	CHEMICAL MFG	VARNISH MFG	
301016	CHEMICAL MFG	AGRICULTURAL CHEM	PHOS ACD/WET PROC
301017	CHEMICAL MFG	AGRICULTURAL CHEM	PHOS ACID THERMAL
301018	CHEMICAL MFG	PLASTICS PRODN	
301019	CHEMICAL MFG	ORGANIC CHEMICALS	PHTHALIC ANHYDRID
301020	CHEMICAL MFG	PRINTING INK MFG	
301021	CHEMICAL MFG	INORGANIC CHEMCLS	SODIUM CARBONATE
301022	CHEMICAL MFG	INORGANIC CHEMCLS	H2SO4-CHAMBER
301023	CHEMICAL MFG	INORGANIC CHEMCLS	H2SO4-CONTACT
301024	CHEMICAL MFG	PLASTICS PRODN	SYNTHC ORGNC FIBR
301025	CHEMICAL MFG	PLASTICS PRODN	CELLULOSIC FIBER
301026	CHEMICAL MFG	PLASTICS PRODN	SYNTHETIC RUBBER
301027	CHEMICAL MFG	AGRICULTURAL CHEM	FERTILIZ AMONNITR
301028	CHEMICAL MFG	AGRICULTURAL CHEM	NRM SPRPHSPHATE
301029	CHEMICAL MFG	AGRICULTURAL CHEM	TRPL SPRPHSPHATE
301030	CHEMICAL MFG	AGRICULTURAL CHEM	AMMONM PHOSPHATES
301031	CHEMICAL MFG	ORGANIC CHEMICALS	TEREPHTHALIC ACID
301032	CHEMICAL MFG	INORGANIC CHEMCLS	SULFUR(ELEMENTAL)
301033	CHEMICAL MFG	AGRICULTURAL CHEM	PESTICIDES
301034	CHEMICAL MFG	ORGANIC CHEMICALS	
301035	CHEMICAL MFG	INORGANIC CHEMCLS	
301038	CHEMICAL MFG	INORGANIC CHEMCLS	SODIUM BICARBNATE
301039	CHEMICAL MFG	INORGANIC CHEMCLS	HYDROGEN CYANIDE
301040	CHEMICAL MFG	AGRICULTURAL CHEM	UREA/UREA-SOLID
301041	CHEMICAL MFG	EXPLOSIVES	NITROCELLULOSE

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
301042	CHEMICAL MFG	ORGANIC CHEMICALS	LEAD ALKYL-NA/PB
301043	CHEMICAL MFG	ORGANIC CHEMICALS	LEAD ALKYLS
301045	CHEMICAL MFG	AGRICULTURAL CHEM	ORGANIC FERTILIZR
301050	CHEMICAL MFG	ORGANIC CHEMICALS	ADHESIVES
301060	CHEMICAL MFG	PHARMACEUTICALS	GENERAL PROCESSES
301070	CHEMICAL MFG	INORGANIC CHEMCLS	GENERAL PROCESSES
301091	CHEMICAL MFG	ORGANIC CHEMICALS	KETONE/ACETONE PROD
301100	CHEMICAL MFG	ORGANIC CHEMICALS	MALEIC ANHYDRIDE
301111	CHEMICAL MFG	INORGANIC CHEMCLS	ASBESTOS CHEMICAL
301112	CHEMICAL MFG	INORGANIC CHEMCLS	ELEMNTL PHOSPHROS
301120	CHEMICAL MFG	ORGANIC CHEMICALS	
301121	CHEMICAL MFG	ORGANIC CHEMICALS	ORGNC DYE/PIGMENT
301124	CHEMICAL MFG	ORGANIC CHEMICALS	CHLOROPRENE
301125	CHEMICAL MFG	ORGANIC CHEMICALS	
301126	CHEMICAL MFG	ORGANIC CHEMICALS	ORGANOHALOGENS
301127	CHEMICAL MFG	ORGANIC CHEMICALS	FLUOROCARBONS
301130	CHEMICAL MFG	AGRICULTURAL CHEM	AMMONIUM SULFATE
301132	CHEMICAL MFG	ORGANIC CHEMICALS	
301133	CHEMICAL MFG	ORGANIC CHEMICALS	ACETIC ANHYDRIDE
301137	CHEMICAL MFG	ORGANIC CHEMICALS	ESTERS PRODUCTN
301140	CHEMICAL MFG	ORGANIC CHEMICALS	ACETYLENE PRODN
301152	CHEMICAL MFG	ORGANIC CHEMICALS	BISPHENOL A
301153	CHEMICAL MFG	ORGANIC CHEMICALS	BUTADIENE
301156	CHEMICAL MFG	ORGANIC CHEMICALS	CUMENE
301157	CHEMICAL MFG	ORGANIC CHEMICALS	CYCLOHEXANE
301158	CHEMICAL MFG	ORGANIC CHEMICALS	CYCLOHEXANONE/CYC
301167	CHEMICAL MFG	ORGANIC CHEMICALS	
301169	CHEMICAL MFG	ORGANIC CHEMICALS	ETHYLBENZENE
301174	CHEMICAL MFG	ORGANIC CHEMICALS	ETHYLENE OXIDE
301176	CHEMICAL MFG	ORGANIC CHEMICALS	GLYCERIN(GLYCERL)
301181	CHEMICAL MFG	ORGANIC CHEMICALS	TOLUENE DIISOCYNT
301190	CHEMICAL MFG	ORGANIC CHEMICALS	METHYL METHACRYLT
301195	CHEMICAL MFG	ORGANIC CHEMICALS	NITROBENZENE
301197	CHEMICAL MFG	ORGANIC CHEMICALS	
301202	CHEMICAL MFG	ORGANIC CHEMICALS	PHENOL
301205	CHEMICAL MFG	ORGANIC CHEMICALS	PROPYLENE OXIDE
301206	CHEMICAL MFG	ORGANIC CHEMICALS	STYRENE
301210	CHEMICAL MFG	ORGANIC CHEMICALS	CAPROLACTUM
301211	CHEMICAL MFG	ORGANIC CHEMICALS	LINEAR ALKYLBENZE
301250	CHEMICAL MFG	ORGANIC CHEMICALS	
301251	CHEMICAL MFG	ORGANIC CHEMICALS	ETHYLENE GLYCOL
301252	CHEMICAL MFG	ORGANIC CHEMICALS	ETHERS
301253	CHEMICAL MFG	ORGANIC CHEMICALS	GLYCOL ETHERS
301254	CHEMICAL MFG	ORGANIC CHEMICALS	
301258	CHEMICAL MFG	ORGANIC CHEMICALS	
301301	CHEMICAL MFG	ORGANIC CHEMICALS	CHLOROBENZENE
301302	CHEMICAL MFG	ORGANIC CHEMICALS	CARBON TETRACHLOR
301303	CHEMICAL MFG	ORGANIC CHEMICALS	ALLYL CHLORIDE
301304	CHEMICAL MFG	ORGANIC CHEMICALS	ALLYL ALCOHOL
301305	CHEMICAL MFG	ORGANIC CHEMICALS	EPICHLOROHYDRIN
301800	CHEMICAL MFG	ORGANIC CHEMICALS	GENERAL PROCESSES

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
301810	CHEMICAL MFG	ORGANIC CHEMICALS	GENERAL PROCESSES
301820	CHEMICAL MFG	ORGANIC CHEMICALS	GENERAL PROCESSES
301830	CHEMICAL MFG	ORGANIC CHEMICALS	GENERAL PROCESSES
301840	CHEMICAL MFG	ORGANIC CHEMICALS	GENERAL PROCESSES
301870	INORGNC CHEM STRG	FIXED ROOF TANKS	
301875	INORGNC CHEM STRG	FLOAT ROOF TANKS	
301885	INORGNC CHEM STRG	PRESSURE TANKS	
301888	CHEMICAL MFG	FUGITIVE EMISSION	NOT CLASSIFIED
301900	CHEMICAL MFG	FUEL-FIRED EQPMNT	
301999	CHEMICAL MFG	MISCELLANEOUS	NOT CLASSIFIED
302001	FOOD/AGRICULTURE	ALFALFA DEHYDRATI	
302002	FOOD/AGRICULTURE	COFFEE ROASTING	
302003	FOOD/AGRICULTURE	COFFEE PRODUCTS	INSTANT COFFEE
302004	FOOD/AGRICULTURE	AGRIC. SERVICES	COTTON GINNING
302005	FOOD/AGRICULTURE	GRAIN ELEVATORS	
302006	FOOD/AGRICULTURE	GRAIN ELEVATORS	COUNTRY ELEVATORS
302007	FOOD/AGRICULTURE	GRAIN MILLING	
302008	FOOD/AGRICULTURE	FEED MANUFACTURE	
302009	FOOD/AGRICULTURE	FERMENTATION	BEER PRODUCTION
302010	FOOD/AGRICULTURE	FERMENTATION	WHISKEY PRODUCTN
302011	FOOD/AGRICULTURE	FERMENTATION	WINE PRODUCTION
302012	FOOD/AGRICULTURE	FISH PROCESSING	FISH MEAL
302013	FOOD/AGRICULTURE	MEAT SMOKING	COMBINED OPERATNS
302014	FOOD/AGRICULTURE	STARCH MFG	COMBINED OPERATNS
302015	FOOD/AGRICULTURE	SUGAR CANE PROCES	GENERAL
302016	FOOD/AGRICULTURE	SUGAR BEET PROCES	DRYER
302017	FOOD/AGRICULTURE	PEANUT PROCESSING	NOT CLASSIFIED
302018	FOOD/AGRICULTURE	CANDY MANUFACTURE	NOT CLASSIFIED
302019	FOOD/AGRICULTURE	VEG OIL PROCESSNG	
302020	FOOD/AGRICULTURE	AGRIC.PRODUCTION	BEEF CATTLE
302021	FOOD/AGRICULTURE	POULTRY/EGG PROD	MANURE HANDLING
302022	FOOD/AGRICULTURE	AGRIC.PRODUCTION	COTTON-ACID DELIN
302026	FOOD/AGRICULTURE	AGRIC.PRODUCTION	SEED PROCESSING
302028	FOOD/AGRICULTURE	AGRIC.PRODUCTION	MUSHROOM GROWING
302030	FOOD/AGRICULTURE	DAIRY PRODUCTS	MILK
302031	FOOD/AGRICULTURE	GRAIN ELEVATORS	EXPORT GRAIN ELEV
302032	FOOD/AGRICULTURE	BAKERIES	BREAD BAKING
302033	FOOD/AGRICULTURE	TOBACCO PRODUCTS	NOT CLASSIFIED
302036	FOOD/AGRICULTURE	DEEP FAT FRYING	COOKING VATS
302038	FOOD/AGRICULTURE	ANIMAL/POLTRY RND	RENDERING
302888	FOOD/AGRICULTURE	FUGITIVE EMISSION	NOT CLASSIFIED
302900	FOOD/AGRICULTURE	FUEL-FIRED EQPMNT	PROCESS HEATERS
302999	FOOD/AGRICULTURE	MISCELLANEOUS	NOT CLASSIFIED
303000	MINING OPERATIONS	METAL ORE MINING	BAUXITE
303001	PRIMARY METALS	ALUMINUM	ELECTRO-REDUCTION
303002	PRIMARY METALS	ALUMINUM	HYDROXIDE CALCING
303003	PRIMARY METALS	IRON & STEEL	BY-PRODUCT COKE
303004	PRIMARY METALS	IRON & STEEL	BEEHIVE COKE
303005	PRIMARY METALS	COPPER SMELTING	
303006	PRIMARY METALS	FERROALLOY	OPEN FURNACE
303007	PRIMARY METALS	FERROALLOY	SEMICOVERED FURNC

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
303008	PRIMARY METALS	IRON & STEEL	
303009	PRIMARY METALS	IRON & STEEL	
303010	PRIMARY METALS	LEAD SMELTING	
303011	MINING OPERATIONS	METAL ORE MINING	MOLYBEDENUM
303012	MINING OPERATIONS	METAL ORE MINING	TITANIUM ORE
303013	MINING OPERATIONS	METAL ORE MINING	GOLD MINING
303014	MINING OPERATIONS	METAL ORE MINING	BARIUM ORE
303023	MINING OPERATIONS	METAL ORE MINING	TACONITE IRON ORE
303024	MINING OPERATIONS	METAL ORE MINING	
303030	PRIMARY METALS	ZINC SMELTING	
303888	PRIMARY METALS	FUGITIVE EMISSION	NOT CLASSIFIED
303900	PRIMARY METALS	FUEL-FIRED EQPMNT	
303999	PRIMARY METALS	MISCELLANEOUS	NOT CLASSIFIED
304001	SECONDARY METALS	SEC. ALUMINUM	
304002	SECONDARY METALS	SEC. COPPER	
304003	PRIMARY METALS	IRON/STEEL FOUNDY	GRAY IRON FOUNDRY
304004	SECONDARY METALS	SEC. LEAD	
304005	ELECTRICAL EQPMNT	LEAD BATTERY MFG	
304006	PRIMARY METALS	MAGNESIUM	POT FURNACE
304007	PRIMARY METALS	IRON/STEEL FOUNDY	STEEL FOUNDRY
304008	SECONDARY METALS	SECONDARY ZINC	
304009	PRIMARY METALS	IRON/STEEL FOUNDY	MALLEABLE IRON
304010	PRIMARY METALS	NICKEL	
304020	ELECTRICAL EQPMNT	FURNACE ELECTRODE	
304022	SECONDARY METALS	METAL HEAT TREATG	
304040	SECONDARY METALS	METALLIC COATING	LEAD CABLE COATNG
304049	SECONDARY METALS	MISC CAST/FABRCTN	WAX BURNOUT OVEN
304050	SECONDARY METALS	MISC CAST/FABRCTN	NOT CLASSIFIED
304888	SECONDARY METALS	FUGITIVE EMISSION	NOT CLASSIFIED
304900	SECONDARY METALS	FUEL-FIRED EQPMNT	
304999	SECONDARY METALS	MISCELLANEOUS	NOT CLASSIFIED
305001	PETROLEUM INDRY	ASPHALT ROOFING	
305002	PETROLEUM INDRY	ASPHALT CONCRETE	
305003	MINERAL PRODUCTS	BRICK MFG	
305004	MINERAL PRODUCTS	CALCIUM CARBIDE	
305005	MINERAL PRODUCTS	CASTABLE REFRACTY	
305006	MINERAL PRODUCTS	CEMENT MFG	DRY PROCESS
305007	MINERAL PRODUCTS	CEMENT MFG	WET PROCESS
305008	MINERAL PRODUCTS	CERAMIC CLAY MFG	
305009	MINERAL PRODUCTS	CLAY/FLYASH SINTR	
305010	MINING OPERATIONS	COAL	
305011	MINERAL PRODUCTS	CONCRETE BATCHING	
305012	MINERAL PRODUCTS	FIBERGLASS	
305013	MINERAL PRODUCTS	FRIT MFG	ROTARY FURNACE
305014	MINERAL PRODUCTS	GLASS MFG	
305015	MINERAL PRODUCTS	GYPSUM MFG	
305016	MINERAL PRODUCTS	LIME MFG	
305017	MINERAL PRODUCTS	MINERAL WOOL	
305018	MINERAL PRODUCTS	PERLITE MFG	VERTICAL FURNACE
305019	MINING OPERATIONS	NONMETALLIC MINRL	PHOSPHATE ROCK
305020	MINING OPERATIONS	NONMETALLIC MINRL	STONE QUARRYING
305021	MINING OPERATIONS	NONMETALLIC MINRL	SALT MINING

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
305022	MINING OPERATIONS	NONMETALLIC MINRL	POTASH PRODUCTION
305024	MINING OPERATIONS	NONMETALLIC MINRL	MAGNESIUM CRBNATE
305025	MINING OPERATIONS	NONMETALLIC MINRL	SAND/GRAVEL
305026	MINING OPERATIONS	NONMETALLIC MINRL	DIATOMACOUS EARTH
305030	MINERAL PRODUCTS	CERAMIC ELEC PRTS	NOT CLASSIFIED
305031	MINING OPERATIONS	NONMETALLIC MINRL	ASBESTOS MINING
305032	MINING OPERATIONS	NONMETALLIC MINRL	ASBESTOS MILLING
305033	MINING OPERATIONS	NONMETALLIC MINRL	VERMICULITE
305040	MINING OPERATIONS	UNSPECIFIED ORE	SEE COMMENT
305100	MINERAL PRODUCTS	BULK MATERIALS	ELEVATORS
305101	MINERAL PRODUCTS	BULK MATERIALS	CONVEYORS
305102	MINERAL PRODUCTS	BULK MATERIALS	STOAGE BINS
305103	MINERAL PRODUCTS	BULK MATERIALS	OPEN STOCKPILES
305104	MINERAL PRODUCTS	BULK MATERIALS	UNLOADING OPERATN
305105	MINERAL PRODUCTS	BULK MATERIALS	LOADING OPERATION
305150	MINERAL PRODUCTS	NONMETALLIC MINRL	CALCINING-GENERAL
305888	MINERAL PRODUCTS	FUGITIVE EMISSION	NOT CLASSIFIED
305900	MINERAL PRODUCTS	FUEL-FIRED EQPMNT	
305999	MINERAL PRODUCTS	MISCELLANEOUS	NOT CLASSIFIED
306001	PETROLEUM INDRY	PETROLEUM REFNG	PROCESS HEATERS
306002	PETROLEUM INDRY	PETROLEUM REFNG	CATALYTIC CRACKNG
306003	PETROLEUM INDRY	PETROLEUM REFNG	CATALYTIC CRACKNG
306004	PETROLEUM INDRY	PETROLEUM REFNG	BLOWDOWN SYSTEM
306005	PETROLEUM INDRY	FUGITIVE HC EMIS	
306006	PETROLEUM INDRY	PETROLEUM REFNG	VACUUM DISTILATN
306007	PETROLEUM INDRY	PETROLEUM REFNG	COOLING TOWERS
306008	PETROLEUM INDRY	FUGITIVE HC EMIS	
306009	PETROLEUM INDRY	PETROLEUM REFNG	FLARES
306010	PETROLEUM INDRY	PETROLEUM REFNG	SLUDGE CONVERTER
306011	PETROLEUM INDRY	PETROLEUM REFNG	ASPHALT BLOWING
306012	PETROLEUM INDRY	PETROLEUM REFNG	FLUID COKING
306014	PETROLEUM INDRY	PETROLEUM REFNG	PETROLEUM COKE
306015	PETROLEUM INDRY	PETROLEUM REFNG	BAUXITE BURNING
306099	PETROLEUM INDRY	PETROLEUM REFNG	INCINERATORS
306100	PETROLEUM INDRY	LUBE OIL MFG	GENERAL
306888	PETROLEUM INDRY	FUGITIVE EMISSION	NOT CLASSIFIED
306999	PETROLEUM INDRY	MISCELLANEOUS	NOT CLASSIFIED
307001	PULP & PAPER	KRAFT PULPING	
307002	PULP & PAPER	SULFITE PULPING	
307003	PULP & PAPER	SEMICHEMICAL PULP	
307004	PULP & PAPER	PULPBOARD	
307005	WOOD PRODUCTS	WOOD PRESS TREAT	CREOSOTE
307007	WOOD PRODUCTS	PLYWOOD/PARTBOARD	
307008	WOOD PRODUCTS	SAWMILL OPERATION	
307011	PULP & PAPER	PAPER COATING	EXTRUSION COATING
307013	PULP & PAPER	MISC. PAPER PROD	INSULATION FROM
307020	WOOD PRODUCTS	FURNITURE MFG	NOT CLASSIFIED
307030	WOOD PRODUCTS	MISCELLANEOUS	
307888	WOOD PRODUCTS	FUGITIVE EMISSION	NOT CLASSIFIED
307900	WOOD PRODUCTS	FUEL FIRED EQPMNT	
307999	WOOD PRODUCTS	MISCELLANEOUS	NOT CLASSIFIED

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
308001	RUBBER/PLASTICS	TIRE MFG	
308005	RUBBER/PLASTICS	TIRE RETREADING	TIRE BUFFING
308006	RUBBER/PLASTICS	MISC.RUBBER PROD	NOT CLASSIFIED
308007	RUBBER/PLASTICS	FAB. PLASTIC PROD	
308900	RUBBER/PLASTICS	FUEL FIRED EQPMNT	
308999	RUBBER/PLASTICS	MISCELLANEOUS	NOT CLASSIFIED
309001	FABRICATED METALS	IRON/STEEL	NOT CLASSIFIED
309002	FABRICATED METALS	ABRASIVE BLASTING	OF METAL PARTS
309003	FABRICATED METALS	ABRASIVE CLEANING	OF METAL PARTS
309010	FABRICATED METALS	ELECTROPLATING	ENTIRE PROCESS
309011	FABRICATED METALS	CONVERSION COATNG	
309015	FABRICATED METALS	CHEMICAL MILLING	OF METAL PARTS
309016	FABRICATED METALS	PIPE COATING	
309020	FABRICATED METALS	CAN MAKING OPRNS	NOT CLASSIFIED
309025	FABRICATED METALS	DRUMS/BARRELS	DRUM CLEANING
309030	FABRICATED METALS	MACHINING OPRNS	
309040	FABRICATED METALS	METAL DEPOSITION	
309060	FABRICATED METALS	PORCELAIN ENAMEL/	CERAMIC GLAZE
309888	FABRICATED METALS	FUGITIVE EMISSION	NOT CLASSIFIED
309900	FABRICATED METALS	FUEL FIRED EQPMNT	
309999	FABRICATED METALS	MISCELLANEOUS	NOT CLASSIFIED
310001	OIL & GAS PRODN	CRUDE OIL PRODN	
310002	OIL & GAS PRODN	NATURAL GAS PRODN	
310004	OIL & GAS PRODN	FUEL-FIRED EQPMNT	
310888	OIL & GAS PRODN	FUGITIVE EMISSION	NOT CLASSIFIED
311001	CONSTRUCTION	BLDG CONTRACTORS	NOT CLASSIFIED
311002	CONSTRUCTION	SPL TRADE CONTRCT	NOT CLASSIFIED
312999	MACHINERY	MISCELLANEOUS	NOT CLASSIFIED
313070	ELECTRICAL EQPMNT	WINDINGS RECLAMTN	INCINERATOR OVEN
313900	ELECTRICAL EQPMNT	FUEL FIRED EQPMNT	PROCESS HEATERS
313999	ELECTRICAL EQPMNT	MISCELLANEOUS	NOT CLASSIFIED
314009	TRANSPORTN EQPMNT	GENERAL PROCESSES	SOLDER JOINT
314010	TRANSPORTN EQPMNT	BRAKE SHOE DEBOND	INCINERATOR OVEN
314011	TRANSPORTN EQPMNT	AUTO BODY SALVAGE	BODY SHREDDING
314999	TRANSPORTN EQPMNT	MISCELLANEOUS	NOT CLASSIFIED
315010	MISC. INDUSTRIES	PHOTOGRAPHIC EQPT	PHOTOCOPY MACHINE
315020	MISC. INDUSTRIES	HOSPITALS	STERILIZATION
320999	LEATHER PRODUCTS	MISCELLANEOUS	NOT CLASSIFIED
330001	TEXTILE PRODUCTS	GENERAL FABRICS	NOT CLASSIFIED
330002	RUBBER/PLASTICS	RUBBERIZED FABRIC	
330003	TEXTILE PRODUCTS	CARPET OPERATNS	NOT CLASSIFIED
330004	TEXTILE PRODUCTS	FABRIC FINISHING	NOT CLASSIFIED
330005	TEXTILE PRODUCTS	APPAREL	NOT CLASSIFIED
330888	TEXTILE PRODUCTS	FUGITIVE EMISSION	NOT CLASSIFIED
360001	PRINTING/PUBLISH	TYPESETTING	LEAD REMELTING
390001	INDUSTRIAL PROCES	INPROCESS FUEL	ANTHRACITE COAL
390002	INDUSTRIAL PROCES	INPROCESS FUEL	BITUMINOUS COAL
390003	INDUSTRIAL PROCES	INPROCESS FUEL	LIGNITE
390004	INDUSTRIAL PROCES	INPROCESS FUEL	RESIDUAL OIL
390005	INDUSTRIAL PROCES	INPROCESS FUEL	DISTILLATE OIL
390006	INDUSTRIAL PROCES	INPROCESS FUEL	NATURAL GAS

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
390007	INDUSTRIAL PROCES	INPROCESS FUEL	PROCESS GAS
390008	INDUSTRIAL PROCES	INPROCESS FUEL	COKE
390009	INDUSTRIAL PROCES	INPROCESS FUEL	WOOD
390010	INDUSTRIAL PROCES	INPROCESS FUEL	LPG
390012	INDUSTRIAL PROCES	INPROCESS FUEL	SOLID WASTE FUEL
390013	INDUSTRIAL PROCES	INPROCESS FUEL	LIQUID WASTE FUEL
399900	INDUSTRIAL PROCES	MIS IND-FUEL EQPT	
399999	INDUSTRIAL PROCES	MISCELLANEOUS	NOT CLASSIFIED
401001	ORGANIC SOLVENT	DRY CLEANING	
401002	ORGANIC SOLVENT	VAPOR DEGREASING	
401003	ORGANIC SOLVENT	COLD CLEANING	
401004	ORGANIC SOLVENT	TEXTILE MFG	FABRIC SCOURING
401888	ORGANIC SOLVENT	FUGITIVE EMISSION	NOT CLASSIFIED
402001	ORGANIC SOLVENT	SURFACE COATING	PAINT-GENERAL
402002	ORGANIC SOLVENT	SURFACE COATING	PAINT-GENERAL
402003	ORGANIC SOLVENT	SURFACE COATING	VARNISH/SHELLAC
402004	ORGANIC SOLVENT	SURFACE COATING	LACQUER
402005	ORGANIC SOLVENT	SURFACE COATING	ENAMEL
402006	ORGANIC SOLVENT	SURFACE COATING	PRIMER
402007	ORGANIC SOLVENT	SURFACE COATING	ADHESIVE
402008	ORGANIC SOLVENT	SURFACE COATING	COATING OVEN
402009	ORGANIC SOLVENT	SURFACE COATING	THINNING SOLVENT
402010	ORGANIC SOLVENT	SURFACE COATING	OVEN HEATER
402011	ORGANIC SOLVENT	SURFACE COATING	
402012	ORGANIC SOLVENT	SURFACE COATING	FABRIC DYEING
402013	ORGANIC SOLVENT	SURFACE COATING	PAPER COATING
402014	ORGANIC SOLVENT	SURFACE COATING	LARGE APPLIANCES
402015	ORGANIC SOLVENT	SURFACE COATING	MAGNET WIRE
402016	ORGANIC SOLVENT	SURFACE COATING	
402017	ORGANIC SOLVENT	SURFACE COATING	CAN COATING
402018	ORGANIC SOLVENT	SURFACE COATING	COIL COATING
402019	ORGANIC SOLVENT	SURFACE COATING	WOOD FURNITURE
402020	ORGANIC SOLVENT	SURFACE COATING	METAL FURNITURE
402021	ORGANIC SOLVENT	SURFACE COATING	FLATWOOD PRODUCTS
402022	ORGANIC SOLVENT	SURFACE COATING	PLASTIC PARTS
402023	ORGANIC SOLVENT	SURFACE COATING	LARGE SHIPS
402024	ORGANIC SOLVENT	SURFACE COATING	LARGE AIRCRAFT
402025	ORGANIC SOLVENT	SURFACE COATING	MISC.METAL PARTS
402026	ORGANIC SOLVENT	SURFACE COATING	STEEL DRUMS
402888	ORGANIC SOLVENT	SURFACE COATING	FUGITIVF EMISSION
402900	ORGANIC SOLVENT	SURFACE COATING	FLARES
402999	ORGANIC SOLVENT	SURFACE COATING	MISCELLANEOUS
403001	PETROLEUM STORAGE	FIXED ROOF TANKS	
403002	PETROLEUM STORAGE	FLOAT ROOF TANKS	
403003	PETROLEUM STORAGE	VAR.VAPOR SP.TNKS	WORKING LOSS
403010	PETROLEUM STORAGE	FIXED ROOF TANKS	
403011	PETROLEUM STORAGE	FLOAT ROOF TANKS	
403012	PETROLEUM STORAGE	VAR.VAPOR SP.TNKS	
403888	PETROLEUM STORAGE	FUGITIVE EMISSION	NOT CLASSIFIED
403999	PETROLEUM STORAGE	MISCELLANEOUS	NOT CLASSIFIED
404001	BULK TERMINALS	FIXED ROOF TANKS	

(CONTIUNED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
404002	BULK PLANTS	FIXED ROOF TANKS	
404003	OIL & GAS PRODN	CRUDE OIL STORAGE	
404004	PETROLEUM STORAGE	UNDERGROUND TANKS	
405001	PRINTING/PUBLISH	PRINTING PROCESS	DRYER
405002	PRINTING/PUBLISH	PRINTING PROCESS	
405003	PRINTING/PUBLISH	PRINTING PROCESS	
405004	PRINTING/PUBLISH	PRINTING PROCESS	
405005	PRINTING/PUBLISH	PRINTING PROCESS	
405006	PRINTING/PUBLISH	PRINTING PROCESS	INK MIXING
405007	PRINTING/PUBLISH	PRINTING PROCESS	SOLVENT STORAGE
405888	PRINTING/PUBLISH	FUGITIVE EMISSION	NOT CLASSIFIED
406001	PETROLEUM MARKTNG	TANK CARS/TRUCKS	
406002	PETROLEUM MARKTNG	MARINE VESSELS	
406003	PETROLEUM MARKTNG	SERVICE STATIONS	STAGE I
406004	PETROLEUM MARKTNG	SERVICE STATIONS	STAGE II
406888	PETROLEUM MARKTNG	FUGITIVE EMISSION	NOT CLASSIFIED
407004	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407008	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407016	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407020	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407032	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407036	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407040	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407044	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407048	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407052	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407056	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407060	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407064	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407068	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407076	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407080	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407084	ORGANIC CHEM STRG	FIXED ROOF TANKS	
407172	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407176	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407180	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407208	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407220	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407228	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407232	ORGANIC CHEM STRG	FLOAT ROOF TANKS	
407812	ORGANIC CHEM STRG	PRESSURE TANKS	
407816	ORGANIC CHEM STRG	PRESSURE TANKS	
407820	ORGANIC CHEM STRG	PRESSURE TANKS	
407824	ORGANIC CHEM STRG	PRESSURE TANKS	
407832	ORGANIC CHEM STRG	PRESSURE TANKS	
407848	ORGANIC CHEM STRG	PRESSURE TANKS	
407860	ORGANIC CHEM STRG	PRESSURE TANKS	
407864	ORGANIC CHEM STRG	PRESSURE TANKS	
407872	ORGANIC CHEM STRG	PRESSURE TANKS	
407999	ORGANIC CHEM STRG	MISCELLANEOUS	SPECIFY IN COMMTS
408999	ORGNC CHEM TRNSPT	MISCELLANEOUS	

(CONTINUED)

TABLE B-1 (CONTINUED)

SCC	SOURCE DESCRIPTION/PROCESS		
490001	ORGANIC SOLVENT	MISCELLANEOUS	SOLVENT EXTRACTN
490002	ORGANIC SOLVENT	MISCELLANEOUS	SOLVENT RECOVERY
490003	ORGANIC SOLVENT	MISCELLANEOUS	RAILCAR CLEANING
490004	ORGANIC SOLVENT	MISCELLANEOUS	TANK TRUCK CLEANG
490900	ORGANIC SOLVENT	MISCELLANEOUS	INCINERATORS/FLARES
490999	ORGANIC SOLVENT	MISCELLANEOUS	NOT CLASSIFIED
501001	SOLID WASTE DISPL	GOVERNMENT	MUNICIPAL INCIN
501002	SOLID WASTE DISPL	GOVERNMENT	OPEN BURNING DUMP
501005	SOLID WASTE DISPL	GOVERNMENT	OTHER INCINERATOR
501006	SOLID WASTE	GOVERNMENT	FIRE FIGHTING
501007	SOLID WASTE DISPL	GOVERNMENT	SEWAGE TREATMENT
501900	SOLID WASTE DISPL	GOVERNMENT	AUX.FUEL/NO EMSNS
502001	SOLID WASTE DISPL	COMMERCL/INSTITNL	INCINERATION-GENL
502002	SOLID WASTE DISPL	COMMERCL/INSTITNL	OPEN BURNING
502003	SOLID WASTE DISPL	COMMERCL/INSTITNL	APARTMENT INCIN
502005	SOLID WASTE DISPL	COMMERCL/INSTITNL	INCINERATION-SPCL
502006	SOLID WASTE DISPL	COMMERCL/INSTITNL	LANDFILL DUMP
502009	SOLID WASTE DISPL	COMMERCL/INSTITNL	
502900	SOLID WASTE DISPL	COMMERCL/INSTITNL	AUX.FUEL/NO EMSNS
503001	SOLID WASTE DISPL	INDUSTRIAL	INCINERATION
503002	SOLID WASTE DISPL	INDUSTRIAL	OPEN BURNING
503005	SOLID WASTE DISPL	INDUSTRIAL	INCINERATOR
503006	SOLID WASTE DISPL	INDUSTRIAL	LANDFILL DUMP
503007	SOLID WASTE DISPL	INDUSTRIAL	LIQUID WASTE
503008	SOLID WASTE DISPL	INDUSTRIAL	
503009	SOLID WASTE DISPL	INDUSTRIAL	
503900	SOLID WASTE DISPL	INDUSTRIAL	AUX.FUEL/NO EMSNS

Clean Air Act Amendments

Cost Comparisons

January 23, 1990

Office of Air and Radiation
United States Environmental Protection Agency

Clean Air Act Amendments

Cost Comparisons

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Clean Air Act Amendments

Cost Comparisons

EXECUTIVE SUMMARY

Last June, President Bush announced a comprehensive proposed set of amendments to the current Clean Air Act. The goal of this legislation is simple -- to secure the right of all Americans to breathe clean air and live in a cleaner environment. Moreover, by utilizing innovative and cost effective pollution control and prevention practices, the President's proposal protects our public and environmental health without hindering our nation's economic viability.

Both the House and the Senate have proposed similar bills to amend the Clean Air Act. This executive summary compares the economic costs of the Administration's original proposal, the House amendments to that original proposal (H.R. 3030 as reported), and the current Senate proposal (S. 1630).

All three proposals seek common environmental goals; curbing acid rain, improving urban air quality, and reducing toxic air emissions. These goals are achieved in different ways however -- differences that will greatly affect the overall cost of clean air. By restricting the discretion of EPA to implement the new clean air provisions and by using federal mandates rather than local solutions, H.R. 3030, and to a much greater degree the Senate bill, result in higher costs with little additional environmental benefits.

As introduced, the President's original set of amendments is estimated to cost $18.9 billion annually in the year 2005. H.R. 3030 as reported would cost $22.2 billion and the Senate proposal would cost $41.9 billion by the year 2005, or more than double the cost of the original Administration bill. The relative magnitudes of the costs are similar in the early years after implementation. The original Administration bill is estimated to cost $6.8 billion in 1995, H.R. 3030 (as reported) $8.0 billion, and S. 1630 $12.0 billion annually by 1995.

Each title of the proposed bills has important differences that result in substantial cost differences. The overall cost of nonattainment provisions of the Senate bill are more than $11 billion more than the Administration nonattainment provisions. The majority of this difference (over $7 billion) is due to the tighter automotive tailpipe emission standards in S. 1630. This $7 billion dollar increased cost accounts for minor improvements (1-2%) in volatile organic chemical (VOC) reductions over the provisions of the Administration and House bills.

In the air toxics title, the Senate's residual risk requirement is estimated to cost approximately $4.5 billion more than the Administration or House bills. These costs are due largely to the potential closure of industrial sources unable to meet the nondiscretionary "bright line" 1×10^{-4} provision of the Senate bill. (Any source that imposes a cancer risk greater than 1 in 10,000 to the "maximum exposed individual" would be required to shut down.) In addition, the more stringent leak detection and accidental release provisions of S. 1630 are expected to cost approximately $2.5 billion more than either the Administration or House bill.

In the acid deposition provisions, the Senate bill is expected to cost approximately $400 million more annually and result in relatively little additional reductions of NOx and SO2.

In addition to these differences in specific provisions, the Senate bill adds important provisions that are not contained in the Administration or the House bill. These additional provisions will increase the cost of the Senate bill beyond the current estimate. Some of the major additions to the Senate bill (for which costs have not been estimated) include:

- The carbon dioxide motor vehicle standards will in effect increase the required motor vehicle mileage standards to 33 miles per gallon by 1996 and 40 mpg by the year 2000. The additional per-vehicle technology costs, possible losses in safety, performance and other attributes valued by the car-buying public and the potentially disruptive effect on the competitiveness of the U.S. automotive industry are not considered in the overall Senate bill costs.

- The costs of phasing out the production and use of ozone depleting chlorofluorocarbons, halons, and carbon tetrachloride according to the schedule in the Senate bill will exceed those expected as a result of the current Montreal Protocol. These costs are not included in the overall Senate estimate.

- The Senate acid deposition provisions require federally-owned facilities to obtain 10% of their electricity supply from alternative clean sources. To the extent that these alternative sources are costlier than current sources, the cost of electricity to these facilities will be increased. These costs are not reflected in the acid deposition costs of the Senate bill.

- Significant Great Lakes and coastal waters air toxic monitoring networks and research programs are required in the Senate bill. The costs of these provisions have not been estimated or included.
- The municipal waste combustor provisions of the Senate bill would impose more stringent controls on very small waste combustors compared to the proposed EPA regulations. These costs are not included in the analysis.
- The cost of the Senate bill does not reflect any additional costs for transportation control measures in the Senate bill. For example, employers that are not able to reduce the average number of passengers per car would be required to pay a monthly fee.

In sum, either by addition of provisions beyond the scope of the President's original set of Clean Air Act provisions or by omission of provisions designed to attain environmental benefits in the most cost-effective manner, S. 1630 and to a lesser extent H.R. 3030 (as reported) result in a higher price tag for clean air. With overall costs for clean air in the billions, rather than millions of dollars, these cost differences could have a significant impact on the nation's economic health without providing substantial additional environmental benefit.

The remainder of this report compares the costs of parallel provisions included within each bill and discusses important differences between each title. All cost estimates included should be considered preliminary and could change pending additional analysis or changes to the provisions analyzed.

CLEAN AIR ACT AMENDMENTS

ANNUAL COST COMPARISON
(million $)

	1995			2005		
	Administration[1]	House (H.R. 3030)[2]	Senate (S.1630)	Administration	House (H.R. 3030)	Senate (S. 1630)
NONATTAINMENT	*5,400*	*6,600*	*8,500*	*10,100*	*11,900*	*23,200*
ACID RAIN	*400*	*400*	*300*	*4,100*	*4,100*	*4,500*
AIR TOXICS	*1,000*	*1,000*	*3,200*	*4,700*	*6,700*	*14,200*
TOTAL ANNUAL COSTS ("best" estimate)	$6,800	$8,000	$12,000	$18,900	$22,200	$41,900

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[1] As transmitted by the President.

[2] Administration bill as amended in Health and Environment Subcommittee.

CLEAN AIR ACT AMENDMENTS

ANNUAL COST COMPARISON
(million $)

	1995			2005		
	Administration[1]	House (H.R. 3030)[2]	Senate (S.1630)	Administration	House (H.R. 3030)	Senate (S. 1630)
NONATTAINMENT	*5,400*	*6,600*	*8,500*	*10,100*	*11,900*	*23,200*
Stationary	2,207	2,207	2,707	2,350	2,350	2,920
Motor Vehicles/Fuels[A]	1,635	2,685	3,376	1,691	3,494	11,413
Area Specific[B]	542	732	1,306	589	799	1,244
Progress Requirements	680	656	369	5,150	4,940	7,000
Fees	300	300	755	300	300	600
ACID RAIN[C]	*400*	*400*	*300*	*4,100*	*4,100*	*4,500*
AIR TOXICS	*1,000*	*1,000*	*3,200*	*4,700*	*6,200*	*14,200*
Phase I MACT[D]	1,010	1,010	2,603	3,145	3,145	4,141
Mobile Sources	0	0	0	0	1,505	1,500
Accidental, Monitoring & Leak Detection	0	0	591	84	84	2,591
Residual Risk[E]						
Unreasonable Risk	0	0	0	1,500	1,500	---
1×10^{-4} & 1×10^{-6} Risk	0	0	0	---	---	6,000
TOTAL ANNUAL COSTS ("best" estimate)	$6,800	$8,000	$12,000	$18,900	$22,200	$41,900

[See following pages for Notes A-E]

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[1] As transmitted by the President.

[2] Administration bill as amended in Health and Environment Subcommittee.

Additional Notes for Cost Comparison Table

Nonattainment Cost Notes

A.1 The EPA-estimated cost increase for the full set of Phase 2 standards in the Senate bill represents about 5 percent of the average purchase price of a car. Economists generally agree that in the short term this will reduce new car sales by about 5 percent from whatever they would otherwise be. The transportation services that would have been provided by these lost units will be made up via older cars being kept in service longer and used more intensively. The reduction in emissions benefits from tailpipe hydrocarbon controls and the increased progress requirement reductions reflect this price effect.

A.2 The tailpipe standard cost for the original Administration bill does not reflect possible savings from permitting averaging across models. The original Administration bill would permit averaging only under conditions that preserve the emission reductions otherwise achieved by applicable standards. EPA believes that even with this constraint, averaging might provide industry and consumers with significant savings and/or more product choice. It can allow manufacturers to avoid high per vehicle development and hardware costs on low-volume or difficult-to-control models by substituting extra reductions from models with more emissions payback per dollar spent. It can also allow new model production to start on schedule despite delays in achieving full compliance. The standards proposed by the Administration are feasible with known technology for all models, and EPA would expect that averaging would be used only sparingly, with moderate cost savings overall but significant savings for a fraction of customers. If, for example, averaging saved one-half the cost of control on 10 percent of production, the overall cost of the tailpipe standards would be reduced 5 percent.

B. The Senate bill lowers the ton per year cutoff to 25 tpy in long-term nonattainment areas and 10 tpy in Los Angelas for reasonably available control technology (RACT). This provision will automatically subject these smaller sources to controls. In the Administration bill, local areas retain the discretion to regulate such sources as deemed necessary to meet the progress requirements. Any additional costs of the less flexible Senate RACT standards are not reflected in the area source cost estimates.

Acid Rain Cost Notes

C.1 The present value of the cost of the Administration proposal is $13 - $18 billion (1988$). The present value of the Senate bill is $14 - $22 billion. The $1 - $4 billion dollar additional cost of the Senate bill is due to the additional NOx requirements and the one year earlier starting date of each phase of reductions.

C.2 S. 1630 contains additional requirements for federally owned facilities as part of the Title IV Acid Deposition Control provisions. Sec. 403 requires federally owned facilities operating in affected utility service areas to install cost effective energy conservation improvements and to utilize renewable and alternative clean energy technologies to satisfy at least 10 percent of each facility's electricity needs.

The requirement to transfer 10% of the electricity demand of these facilities to clean alternative sources could greatly increase the cost of electricity if the price of the clean substitute was more than current supply. Moreover, this requirement may only result in a reshuffling of power usage, resulting in no net environmental benefit. By requiring facilities to purchase electricity from nonfossil sources for example, the requirement would shift nonfossil power from existing customers to federal facilities and fossil capacity previously used by federal facilities to nonfederal facilities.

Air Toxics Cost Notes

D. Part of the Phase I MACT technology costs include costs for controlling toxics from electric utility boilers. EPA's detailed air toxics cost analysis indicates that boiler control costs could range from $750 million to $2.6 billion in the year 2003. This range of control costs does not include the use of scrubbers which may be necessary in some cases to control emissions of acid gaseous emissions (e.g. fluorides, chlorine, formaldehyde). If such gaseous emissions were considered in the analysis, an estimated 230 additional coal-fired generating plants would exceed the major source trigger criteria. Adding scrubbers to these boilers would cost approximately $7.3 billion annually. The control of acid gas emissions and the interplay between the air toxics and acid rain provisions of the various bills will both be elements of the utility boiler study required by the Administration bill.

E. The $6 billion dollar residual risk cost of the Senate bill includes both the potential costs of closure of the sources unable to meet the 1 x 10^{-4} "bright-line" risk goal as well as the costs sources are expected to incur costs in striving to meet the 1 x 10^{-6} Senate residual risk standard. Research on improved control technologies and implementation of better pollution management and control practices will impose costs on those sources who meet the 1 x 10^{-4} risk level but fall short of the 1 x 10^{-6} risk level.

The nationwide cost of this 1 x 10^{-6} residual risk requirement is difficult to estimate. In the most recent NESHAPS regulations promulgated by EPA for stationary sources of benzene, the incremental control costs of reducing risk from 1 x 10^{-4} to 1 x 10^{-6} totaled over $100 million annually for those sources able to meet the stricter standard. Similar or greater costs can be expected for other industrial sources required to meet the Senate's 1 x 10^{-6} residual risk requirement.

In addition to the economic costs of potential industrial source closure resulting from the Senate's 1 x 10^{-4} risk standard, approximately 11,000 - 14,000 workers may lose their jobs.

DISCUSSION OF COST DIFFERENCES

I. Nonattainment

A. Ozone Nonattainment

By the year 2010, each bill results in attainment of the ozone ambient air standard in all areas in the nation. The Senate bill has earlier attainment deadlines than the Administration or House bill, resulting in greater overall costs. By the year 1995, the ozone attainment costs of the Senate bill are $700 million more than the original Administration bill. By 2000, ozone attainment costs are $1.1 billion more, and by 2005 they jump to over $10 billion more annually. The majority of this cost differential is due to the Senate proposal's Phase II automotive tailpipe standards which are estimate to add an additional $500 to the price of each car.

B. Carbon Monoxide Attainment

The more stringent oxygenated fuels provisions of the Senate bill are estimated to cost $320 million in 1995 compared to $117 for the original Administration bill.

II. Acid Rain

The Senate bill is estimated to cost approximately $400 million more than the Administration bill by the year 2005. Each bill achieves similar SO2 reductions (8.2 million tons from 1980 baseline by 2005 for the Administration bill and 8.6 million tons for the Senate bill). Each bill is estimated to result in approximately 2.1 million tons of NOx reductions. Although the NOx reduction requirements are greater in the Senate bill because the incremental reductions would be extremely expensive, the analysis indicates that utilities will comply by substituting SO_2 reductions for part of the NOx reduction requirement. This substitution effect accounts for the 400,000 ton increase in SO_2 reductions in the Senate bill.

The Administration and House bills have the same costs for acid rain control.

III. Air Toxics

In 1995 the Senate air toxics provision is estimated to cost $3.2 billion compared to $1.0 billion for the House and Administration bills. The increased cost is due to urban air toxics monitoring network costs not mandated in the

Administration bill and the earlier potential control of utility boilers. The Administration bill contains a provision to complete a study of the toxic emissions from utility boilers before regulation.

By 2005, the costs of the Senate bill ($14.2 billion) are over double the estimated cost of the amended Administration bill ($6.2 billion). This is due to accidental release and leak detection provisions more stringent than the Administration bill and the potential costs of closure of industrial sources that cannot meet the Senate's 1×10^{-4} "bright-line" residual risk standard.

The major difference between the original Administration and H.R. 3030 is H.R. 3030's more stringent mobile source air toxic requirements which result in an additional $1.5 billion cost -- primarily for the control of benzene.

IV. Additional Senate Provisions

A. Stratospheric Ozone and Global Climate: CFC Phaseout

Title VII of S. 1630, Stratospheric Ozone and Global Climate Protection, requires the scheduled phase out of production of listed CFCs, halons and other ozone depleters. The schedule would require a total ban of production by the year 2000, in contrast to the current international agreement (Montreal Protocol) which only freezes production in 1998 at half of the 1986 levels. In addition, the Senate bill does not provide the Administrator with discretion to consider the toxic potential of CFC substitutes.

The Administration proposal does not contain amendments to the Clean Air Act for the control of stratospheric ozone depletion. EPA and the Administration believe that multilateral negotiations and actions for such control should go forward as scheduled, rather than unilateral action. The process of strengthening the Montreal Protocol is well underway and should be allowed to run its course. Changes to the protocol are schedule to be decided at the second meeting of the of signatories which is scheduled for June 1990. In addition, the agency currently has broad regulatory authority to undertake many of the specific requirements contained in the Senate bill. Moreover, the Administration believes that complicating an already full and complex package of amendments at this stage of the legislative process may unnecessarily jeopardize passage of the bill.

B. Carbon Dioxide Emissions from Automobiles

In response to global warming concerns, S. 1630 requires new cars beginning in 1996 to meet a CO2 standard corresponding to a 33 miles per gallon fuel efficiency level, and beginning in 2000 the standard increases to about 40 miles per gallon.

The Administration and House bills do not contain such a standard and the Administration opposes its inclusion. Multilateral, rather than unilateral approaches, are needed to address global environmental issues such as global warming concerns. The proposed changes to fuel economy levels require detailed consideration of feasibility, cost, and impacts on safety, performance, and other attributes valued by the car buying public. Impacts on U.S. automotive industry competitiveness must also be considered. Finally, as with the addition of the CFC requirements, the inclusion of a CO2 standard into the ongoing amendment process injects a host of new complicated issues into the debate, seriously jeopardizing action on the already crowded clean air agenda.

NONATTAINMENT COST DETAILS

Nonattainment Costs

The following costs tables compare the costs of reducing VOC's for ozone nonattainment purposes for the years 1995, 2000, 2005, and 2010.

Measures analyzed in the tables are divided into five categories.

1. The base program and RVP I represent regulations and standards that are already in force and therefore will affect emissions regardless of how the Clean Air Act is amended. The major controls of the base program are full implementation of existing SIPs, the existing Federal Motor Vehicle Control Program (FMVCP), and new source controls. The cost of the base program and RVP are not included in the totals ascribed to each bill.

2. National stationary measures are those that affect all sources nationwide whether or not they are located in nonattainment areas.

3. Measures that affect motor vehicle emissions are listed as a group.

4. Area specific measures are those that, when mandated by a bill, are applied to a selected number of areas, whether it be all nonattainment areas or a subset of nonattainment areas. (Two of the motor vehicle measures, Stage II and alternative fuels, are also area specific measures).

5. Costs listed as progress requirements are those beyond the specific measures mandated by each bill, but that are necessary to meet interim emission reduction requirements or to attain the standard, whichever is binding. Identifiable controls (for which cost and emission reduction information is available) are applied first. The remainder of the progress requirements is made up of as yet unspecified "assumed" controls for which no specific cost data are available. Costs of assumed controls are estimated to range from $2,000 to $10,000 per ton with a best estimate of $5,000 per ton.

As indicated in the footnotes to Table 3, the percentage reduction is estimated based on what is expected to occur in ozone nonattainment areas. For most categories, the percentage reduction is calculated as the expected 1995 nonattainment area emissions for that category under the current EPA policy minus the modeled 1995 nonattainment area emissions divided by the 1987 nonattainment area total emissions. (For projection years other than 1995, the percentage reduction is calculated in the same way, with that year's emissions substituted into the above relationship.) For measures that are not applied to all nonattainment areas, the percentage reduction is calculated by substituting into the above equation the emissions for the areas where the measure is applied. As an example, stage II refueling controls are only applied in moderate, serious, and severe nonattainment areas in the Administration bill, so the emissions in marginal nonattainment areas are excluded from the calculation for that measure.

In addition to the costs reflected in the tables for ozone nonattainment, each bill contains NOx mobile source costs for ozone attainment, and carbon monoxide attainment costs (oxygenated fuels and cold temperature CO control costs).

These costs are as follows:

NOx Motor Vehicle

Administration	1995 -- $ 380 million	2005 -- $ 415 million
H.R. 3030	1995 -- $1,387 million	2005 -- $1,741 million
S. 1630	1995 -- $1,568 million	2005 -- $2,395 million

Oxygenated Fuels

Administration	1995 -- $ 117 million	2005 -- $ 140 million
H.R. 3030	1995 -- $ 154 million	2005 -- $ 187 million
S. 1630	1995 -- $ 320 million	2005 -- $ 392 million

Cold Temperature Carbon Monoxide

Administration, H.R. 3030, and S. 1630 (costs same for all bills for Phase I standard)

1995 -- $108 million
2005 -- $128 million

In addition to these costs, the Senate provisions will result in additional control costs for the years 2000-2003, for the cost of equipment that must be installed on cars in certain areas prior to the installation of the control equipment required to meet the rest of the Senate bill's Phase II tailpipe standards in 2003.

Table 1
Comparison of Ozone Nonattainment Bills - 1995
(1/23/90)

Measure	Original Administration %VOC(3)	Original Administration Cost(2)	House H.R.3030 %VOC(3)	House H.R.3030 Cost(2)	Senate S.1630 %VOC(3)	Senate S.1630 Cost(2)
Base Program	15.3	-	15.3	-	15.3	-
RVP I	6.4	-	6.4	-	6.4	-
NATIONAL STATIONARY						
TSDF(1)	3.8	1,700	3.8	1,700	3.8	1,700
Municipal Landfills(1)	0.6	65	0.6	65	0.6	65
Cons./Comm. Solvents	0.9	400	0.9	400	2.1	900
Arch. Coatings	1.5	0	1.5	0	1.5	0
Marine Vessels	0.1	42	0.1	42	0.1	42
MOTOR VEHICLES/FUELS						
RVP II	7.5	240	7.5	240	7.5	240
Evap/Running Losses	0.8	60	0.8	60	0.8	60
Tailpipe/Useful Life	<0.1	460	<0.1	430	0.3	870
Refueling:						
Stage II and Onboard	1.3	120	1.3	76 to 236	1.3	130 to 290
Alternative Fuels	<0.1	150	<0.1	150	-	-
AREA SPECIFIC MEASURES						
RACT to 50 tpy	-	-	-	-	0.4	84
New CTG	2.9	400	4.1	590	4.4	480
Enhanced I&M	1.1	73	1.1	73	1.2	92
Basic I&M	-	69	-	69		
Ozone Transport Regions	*	*	*	*	-	250
PROGRESS REQUIREMENTS						
Identifiable Controls	**	130	**	36	**	79
Assumed Controls	**	550	**	620	**	290
NATIONAL TOTALS	42	4,500 (4,100 to 5,000)	43	4,700 (4,300 to 5,300)	46	5,400 (5,300 to 5,700)
RESIDUAL NONATTAINMENT AREAS	19		18		19	

(1) Measures EPA will implement under other legislation
(2) Millions of dollars
(3) Percentage reductions in VOC emissions are estimated from nonattainment area totals or as a percentage of 1987 emissions in the areas where those measures are scheduled to be applied.

* Bill requires assessment to determine nature and extent of controls needed for transport. Additional controls are likely, but estimates are not available.

** Percentage reductions for progress requirements are not shown because they apply only to a limited number of areas.

Table 2
Comparison of Ozone Nonattainment Bills - 2000
(1/23/90)

Measure	Original Administration %VOC(3)	Original Administration Cost(2)	House H.R.3030 %VOC(3)	House H.R.3030 Cost(2)	Senate S.1630 %VOC(3)	Senate S.1630 Cost(2)
Base Program	13.7	-	13.7	-	13.7	-
RVP I	6.7	-	6.7	-	6.7	-
NATIONAL STATIONARY						
TSDF(1)	3.9	1,800	3.9	1,800	3.9	1,800
Municipal Landfills(1)	0.6	67	0.6	67	0.6	67
Cons./Comm. Solvents	1.0	420	1.0	420	2.3	980
Arch. Coatings	1.5	0	1.5	0	1.5	0
Marine Vessels	0.1	47	0.1	47	0.1	47
MOTOR VEHICLES/FUELS						
RVP II	7.6	260	7.6	260	7.6	260
Evap/Running Losses	2.3	63	2.3	63	2.3	63
Tailpipe/Useful Life	0.4	480	0.4	570	0.9	910
Refueling:						
Stage II and Onboard	1.4	140	1.7	82 to 252	1.7	140 to 310
Alternative Fuels	0.2	0	0.2	300	-	-
AREA SPECIFIC MEASURES						
RACT to 50 tpy	-	-	-	-	0.4	84
New CTG	3.4	430	4.4	620	4.7	490
Enhanced I&M	1.1	80	1.1	80	1.2	100
Basic I&M	-	75	-	75		
Ozone Transport Regions	*	*	*	*	-	300
PROGRESS REQUIREMENTS						
Identifiable Controls	-	260	-	63	-	97
Assumed Controls	-	2,300	-	2,200	-	2,400
NATIONAL TOTALS	44	6,400 (5,000 to 8,600)	45	6,800 (5,500 to 9,000)	48	7,900 (6,500 to 10,300)
RESIDUAL NONATTAINMENT AREAS	4		4		4	

(1) Measures EPA will implement under other legislation
(2) Millions of dollars
(3) Percentage reductions in VOC emissions are estimated from nonattainment area totals or as a percentage of 1987 emissions in the areas where those measures are scheduled to be applied.

* Bill requires assessment to determine nature and extent of controls needed for transport. Additional controls are likely, but estimates are not available.

** Percentage reductions for progress requirements are not shown because they apply only to a limited number of areas.

Table 3
Comparison of Ozone Nonattainment Bills - 2005
(1/23/90)

	Original Administration		House H.R.3030 Phase I Only ***		Senate S.1630	
Measure	%VOC(3)	Cost(2)	%VOC(3)	Cost(2)	%VOC(3)	Cost(2)
Base Program	8.6	-	8.6	-	8.6	-
RVP I	7.1	-	7.1	-	7.1	-
NATIONAL STATIONARY						
TSDF(1)	4.0	1,800	4.0	1,800	4.0	1,800
Municipal Landfills(1)	0.6	69	0.6	69	0.6	69
Cons./Comm. Solvents	1.0	430	1.0	430	2.4	1,000
Arch. Coatings	1.5	0	1.5	0	1.5	0
Marine Vessels	0.1	51	0.1	51	0.1	51
MOTOR VEHICLES/FUELS						
RVP II	8.2	280	8.2	280	8.2	280
Evap/Running Losses	3.5	68	3.5	68	3.5	68
Tailpipe/Useful Life	0.6	510	0.6	610	1.2	7,800
Refueling:						
Stage II and Onboard	1.5	150	2.0	90 to 270	1.9	160 to 340
Alternative Fuels	0.9	0	0.4	300	-	-
AREA SPECIFIC MEASURES						
RACT to 50 tpy	-	-	-	-	0.4	84
New CTG	3.4	420	4.6	630	4.9	520
Enhanced I&M	1.2	87	1.2	87	1.2	110
Basic I&M	-	82	-	82		
Ozone Transport Regions	*	*	*	*	-	330
PROGRESS REQUIREMENTS						
Identifiable Controls	-	280	-	70	-	100
Assumed Controls	-	4,900****	-	4,900****	-	7,000*****
NATIONAL TOTALS	42	9,100 (6,200 to 13,900)	43	9,600 (6,700 to 14,400)	46	19,600 (15,500 to 26,400)
RESIDUAL NONATTAINMENT AREAS	3		3		0	

(1) Measures EPA will implement under other legislation
(2) Millions of dollars
(3) Percentage reductions in VOC emissions are estimated from nonattainment area totals or as a percentage of 1987 emissions in the areas where those measures are scheduled to be applied.

* Bill requires assessment to determine nature and extent of controls needed for transport. Additional controls are likely, but estimates are not available.

** Percentage reductions are not shown for progress requirements because they apply only in a limited number of areas.

*** Assumes only phase I tailpipe standards are implemented

**** If the 4 severe areas meet less stringent EKMA estimated reductions for attainment, costs decrease by $270 ($110 to $540)

***** If the 4 Administration bill severe areas meet less stringent EKMA estimated reductions for attainment, costs decrease by $2,700 ($1,100 to $5,400)

Table 4
Comparison of Ozone Nonattainment Bills - 2010
(1/23/90)

Measure	Original Administration %VOC(3)	Original Administration Cost(2)	House H.R.3030 Phase I Only *** %VOC(3)	House H.R.3030 Phase I Only *** Cost(2)	Senate S.1630 %VOC(3)	Senate S.1630 Cost(2)
Base Program	2.9	-	2.9	-	2.9	-
RVP I	7.7	-	7.7	-	7.7	-
NATIONAL STATIONARY						
TSDF(1)	4.0	1,900	4.0	1,900	4.0	1,900
Municipal Landfills(1)	0.6	71	0.6	71	0.6	71
Cons./Comm. Solvents	1.0	440	1.0	440	2.5	1,100
Arch. Coatings	1.6	0	1.6	0	1.6	0
Marine Vessels	0.1	55	0.1	55	0.1	55
MOTOR VEHICLES/FUELS						
RVP II	8.8	310	8.8	310	8.8	310
Evap/Running Losses	4.3	72	4.3	72	4.3	72
Tailpipe/Useful Life	0.8	540	0.8	650	2.9	8,800
Refueling:						
Stage II and Onboard	1.7	160	2.2	99 to 290	2.1	170 to 360
Alternative Fuels	1.4	0	0.6	300	-	-
AREA SPECIFIC MEASURES						
RACT to 50 tpy	-	-	-	-	0.4	84
New CTG	3.6	430	4.8	650	5.1	530
Enhanced I&M	1.3	94	1.3	94	1.3	120
Basic I&M	-	88	-	88		
Ozone Transport Regions	*	*	*	*	-	330
PROGRESS REQUIREMENTS						
Identifiable Controls	-	280	-	78	-	110
Assumed Controls	-	7,800****	-	7,900****	-	8,500*****
NATIONAL TOTALS	40	12,200 (7,600 to 20,100)	41	12,900 (8,200 to 20,800)	44	22,300 (17,300 to 30,900)
RESIDUAL NONATTAINMENT AREAS	0		0		0	

(1) Measures EPA will implement under other legislation
(2) Millions of dollars
(3) Percentage reductions in VOC emissions are estimated from nonattainment area totals or as a percentage of 1987 emissions in the areas where those measures are scheduled to be applied.

* Bill requires assessment to determine nature and extent of controls needed for transport. Additional controls are likely, but estimates are not available.

** Percentage reductions are not shown for progress requirements because they apply only in a limited number of areas.

*** Assumes only Phase I tailpipe standards are implemented

**** If the 4 severe areas meet less stringent EKMA estimated reductions for attainment, costs decrease by $1,900 ($770 to $3,800)

***** If the 4 Administration bill severe areas meet less stringent EKMA estimated reductions for attainment, costs decrease by $3,700 ($1,500 to $7,500)

ACID RAIN COMPARISON

ADDITIONAL ACID RAIN PROVISION AND COST COMPARISON

Low Base Case Flexible to High Base Case Flexible Scenarios

	1995		2005	
	Administration	Senate	Administration	Senate
Utility SO2 (millions tons reduced from 1980 baseline)	-4.1 to -2.8	-3.8 to -2.7 *	-8.6 to -8.2	-8.4 to -8.6
Utility NOx (millions tons)	-0.02	-0.1	-2.0 to -2.1	-2.1 to -2.1
Retrofit Scrubber Capacity (gigawatts)	+0.4 to +0.5	—	+15.0 to +22.0	+14.5 to +34.1
Coal Production (millions of tons)				
N. Appalachia	-16 to -23	-16 to -23	-37 to -35	-28 to -35
Midwest	-32 to -32	-27 to -29	-56 to -50	-55 to -49
C&S Appalachia	+33 to +41	+39 to +43	+59 to +46	+50 to +47
West	+10 to +11	+ 5 to + 7	+31 to +39	+29 to +34
Total U.S.	- 4 to - 3	0 to -2	- 3 to 0	- 4 to - 2

* The NOx reduction requirements are about 0.2 to 0.5 million tons greater in 2005 than in the Administration bill. This chart reflects the projections that utilities will comply by substituting SO2 reductions (at a 1.5 to 1 trading ratio) for part of the NOx reduction requirement.

AIR TOXICS COST DETAILS

UPDATED AIR TOXICS COST COMPARISON

Net Annualized Cost by 1995 (million 1989$)

Source Category	Administration[3]		S. 816	
	Range	Best Estimate	Range	Best Estimate
PHASE I TECHNOLOGICAL CONTROL COSTS				
Major Stationary	505-1,364	935	505-1,365	935
Utility Boilers	0	0	750-2,585	1,668
Area Sources	30 - 119	75	0	0
Mobile Sources	0	0	0	0
MONITORING, ACCIDENTAL RELEASE, DETECTION				
Urban Monitoring	NA	0	87	87
Leak Detection	NA	0	0	0
Accidental Release	NA	0	336-672	504
RESIDUAL RISK COSTS				
Residual Risk	NA	0	NA	0
TOTAL - - - -	$535-$1,483	$1,010	$1,678-$4,709	$3,194

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[3] Original Administration bill and House (H.R. 3030 as reported) have same 1995 costs.

UPDATED AIR TOXICS COST COMPARISON

Net Annualized Cost by 2003 (million 1989$)

Source Category	Administration[1]		S. 816	
	Range	Best Estimate	Range	Best Estimate
PHASE I TECHNOLOGICAL CONTROL COSTS				
Major Stationary	805-3,388	2,097	882-3,468	2,175
Utility Boilers	0-2,585	750	750-2,585	1,668
Area Sources	120 - 475	298	120 - 475	298
Mobile Sources	0	0	0-3,000	1,500
MONITORING, ACCIDENTAL RELEASE, DETECTION				
Urban Monitoring	NA	0	87	87
Leak Detection	NA	0	2,000	2,000
Accidental Release	42 - 126	84	336-672	504
Subtotal - - - -	967-9,584	3,629	7,155-12,287	8,232
RESIDUAL RISK COSTS				
Unreasonable Risk	0 - 5,100	1,500	NA	
1 x 10-4 Bright-Line & 1 x 10-6 Risk Goal[2]	NA		5,100-6,900	6,000
TOTAL - - - -	$967-$14,684	$4,729	$12,255-$19,187	$14,232

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[1] Administration bill as amended in the House (H.R. 3030) has an additional $1.505 billion for the control of mobile source toxics. H.R. 3030 as reported is estimated to cost $6.234 billion.

[2] See Residual Risk additional cost note E on page 8 above.

APPENDIX II

Responses to Post-Hearing Questions

J. BENNETT JOHNSTON, LOUISIANA, CHAIRMAN

DALE BUMPERS, ARKANSAS
WENDELL H. FORD, KENTUCKY
HOWARD M. METZENBAUM, OHIO
BILL BRADLEY, NEW JERSEY
JEFF BINGAMAN, NEW MEXICO
TIMOTHY E. WIRTH, COLORADO
KENT CONRAD, NORTH DAKOTA
HOWELL T. HEFLIN, ALABAMA
JOHN D. ROCKEFELLER IV, WEST VIRGINIA

JAMES A. McCLURE, IDAHO
MARK O. HATFIELD, OREGON
PETE V. DOMENICI, NEW MEXICO
MALCOLM WALLOP, WYOMING
FRANK H. MURKOWSKI, ALASKA
DON NICKLES, OKLAHOMA
CONRAD BURNS, MONTANA
JAKE GARN, UTAH
MITCH McCONNELL, KENTUCKY

DARYL OWEN, STAFF DIRECTOR
D. MICHAEL HARVEY, CHIEF COUNSEL
FRANK M. CUSHING, STAFF DIRECTOR FOR THE MINORITY
GARY G. ELLSWORTH, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

January 29, 1990

William G. Rosenberg
Assistant Administrator for
Air and Radiation
Environmental Protection Agency
Washington, D.C. 20460

Dear Mr. Rosenberg:

Enclosed are additional questions for the record relating to the January 24 and 25, 1990 hearing on Energy Policy Implications of S. 1630.

Because clean air legislation is currently being considered by the full Senate, please provide responses to these questions as soon as possible.

Sincerely,

J. Bennett Johnston
Chairman

JBJ/pjb

Committee Note.--The Environmental Protection Agency had not responded to the following questions at the time the hearing was printed.

FROM SENATOR FORD

Acid Rain - Allowances

Question for EPA Witnesses

Wendell Ford

Q. Does EPA have any estimate as to the costs to various sources for the additional 2% control requirement created by the Administrator's 2% reserve (Section 403(A)(2)(A))? Does it mean that a full compliance plan from a utility will be answered with only 98% of the allowances that utility will need? How do they overcome this shortfall?

A. EPA believes that at 1500 dollars per ton of SO_x the "market should clear." This market clearing cost may be different than the cost to the sources from which the allowances were withheld. It is unclear whether there is any data on this point.

FROM SENATOR FORD

Wendell Ford

Clean Coal Technologies

Question for EPA, DOE, and Clean Coal Coalition Witnesses

Q. As an incentive, S.1630 extends the compliance date for Phase II (2000) sulfur dioxide requirements for existing units which propose to meet those requirements by repowering with clean coal technologies (CCT). By limiting, however, the compliance date extension to units which "repower" with Clean Coal Technology, the bill fails to recognize sulfur reduction technologies that do not involve repowering which DOE is supporting through the CCT program. Is this limitation justified in your opinion?

How much money is being spent by DOE on these excluded clean coal technologies?

Submitted by Sen. Heflin: 1/25/90

Acid Rain - Enforcement

Questions for EPA Witnesses, Mr. Rosenberg
Panel II

Q. Since new criminal enforcement authority under consideration would prevent sources from paying an excess emission fee and continuing to operate in noncompliance, why does this bill provide for civil enforcement actions with penalties of up to $2,000 per excess ton in addition to excess emission fees? Aren't these enforcement measures redundant?

SUBMITED BY SEN. HEFLIN: 1/25/90

FOR EPA WITNESS, MR. ROSENBERG, PANEL II

Q. It appears that the acid rain title of S. 1630 encourages, if not requires, scrubbers on a number of plants. Don't scrubbers decrease the energy efficiency of power plants?

Q. Shouldn't we be encouraging clean coal technologies which enhance efficiency?

Q. The bill seems to assume that there are no clean coal technologies ready to implement now. At the same time, it would appear that any plant which installs a scrubber is postponing for the useful life of the scrubber any consideration of clean coal options, and that delay may be 20 years?

[illegible] Shouldn't we be providing some incentives to utilities to opt for a solution that may be technologically ready but not quite economically competitive?

Hearing on January 24 and 25, 1990

Questions for EPA
from Senator James A. McClure

ACID RAIN

1. There does not appear to be any economic justification for the trading ratios of 1 1/2 NOx for 1 SOx (Section 403(c)). It seems to be an arbitrary assumption. Can you provide us with the technical basis for such a ratio?

2. In crafting the allowance and permit provisions in the acid rain titles of S. 1490 and S. 1630, did your Department give consideration to the "real world" impact this marketing and trading system between utilities would:

   a. Have on electricity reliability in various regions of the country, particularly those regions experiencing rapid growth?

   b. Have on the possible increase of imported oil or imported power as an alternative means to comply with the mandated SO2 and NOx emission reductions? If so, please share with us the results of your analysis.

3. Would you comment on the following statement in the National Research Council report entitled "Acid Deposition, Atmospheric Processes in Eastern North America" dated 1983:

   "In 1981 the National Research Council issued a report titled Atmosphere-Biosphere Interactions: Toward a Better Understanding of the Consequences of Fossil Fuel Combustion. The report focused on the effects on living systems of atmospheric pollutants associated with energy production. One chapter in the report described in detail the state of knowledge concerning the effects of acid precipitation on the biosphere. Based on its survey of field data in sensitive areas and the results of experiments, the report concluded that with respect to sensitive freshwater ecosystems, "It is desirable to have precipitation with pH values no lower than 4.6 to 4.7 throughout such areas, the value at which rates of degradation are detectable by current survey methods. . . In the most seriously affected areas (average precipitation pH of 4.1 to 4.2), this would mean a reduction of 50 percent in deposited hydrogen ions." However, a change in pH, which is measured on a logarithmic scale, from 4.1 to 4.6 corresponds to a threefold decrease in deposited hydrogen ions rather than a twofold decrease.

   The conclusion was misinterpreted in the press and by others (see, for example, Science 214:38 October 2, 1981, and page A of The Washington Post for October 16, 1981) as a recommendation for a 50 percent reduction in emissions of the pollutant gases, sulfur dioxide and the oxides of nitrogen, that are precursors to acid precipitation. While the report concluded that the desired reduction in the deposition of hydrogen ions implies a reduction in emissions, it did not indicate how much additional control of emissions would be required to meet the goal."

4. The need for further reductions in the emission of NOx to control acid rain is more uncertain than the need for sulfur dioxide (SO2) reductions. Nevertheless, S. 1630 contains NOx reduction requirements of 4 million tons, far in excess of S. 1490 goal (2 million tons) -- requirements that could drastically increase the price tag of further acid rain controls by requiring the use of expensive selective catalytic reduction devices and in some cases, in addition to low-NOx burners.

   a. Do you support the President's NOx 2 million tons of reductions or the Environment Committee's stringent 4 million tons? What study recommends such a change?

   b. Do you contemplate utilities using selective catalytic reduction (SCR) technology to meet this 4 million target? If not, what technology? (Low NOx burners will not meet this objective based on actual operating data.

   c. If we accept your assumption that NOx must be controlled so stringently in order to "protect the environment" as you state, why aren't all potential sources controlled -- for example, industrial sources?

5. I understand that selective catalytic reduction (SCR) devices will be required to meet the ambitious NOx removal rates. I also understand that a Title III listed hazardous air pollutant, ammonia is required to make SCR work. Further, that it takes excess ammonia injection to make this device work and that some excess ammonia escapes the process, called "ammonia slip." So, if a facility has to use selected catalytic reduction technology to meet the specified NOx emissions rates, there is going to be "ammonia slip" which may target the source for air toxics controls. Has staff or EPA examined this problem? How will the dramatic increase in demand for ammonia be met within the existing ammonia production capabilities?

6. The Committee bill rejects the President's approach of encouraging the use of low NOx burner (LBN) technology to reduce NOx emissions and, instead, requires specific numerical reductions that may well be unreachable without resort to selective catalytic reduction (SCR) technology.

   a. Is there any scientific basis for setting such ambitious NOx reduction requirements?

   b. Do we know how much the additional cost of this bill will be as a result of this NOx reduction approach?

c. Finally, since SCR utilizes ammonia and ammonia is covered in the toxic title - don't we have a conflict?

7. What is the source of the 0.5 and 0.45 pounds per million BTU NOx emissions limits? It is our understanding that the specified emissions limits in the House bill are based on technology, low NOx burners, but experts state that the only way to achieve the lower Senate reductions is through the use of very expensive selected catalytic reduction. Do you have any analysis to justify the claim that the mandated NOx reductions can be achieved, including an operating margin, without the use of costly selected catalytic reduction? Are these limits int he bill average emissions rates?

8. Both S. 1630 and S. 1490 establishes a procedure for emission allowance trading. The procedure purports to permit utilities to trade allowances in tons of NOx and SO2. There are fears that it would create administrative burdens both for EPA and utilities.

   I understand that EPA has retained a consultant to write the details of the allowance trading program. We have also heard from EPA that the allowance program is a simple procedure. If it's so simple, why do you need a consultant to write a "complex" procedure? Also, how were the costs, mechanisms and impacts figured into the bill if such a procedure is yet to be designed?

9. If recordation of allowance transfers is intended to be simply a pro forma step, why doesn't the bill promote certainty in the trading market by providing for automatic recordation of allowances within a specified period of days or weeks? Doesn't the risk of bureaucratic delay in recording allowance transfers unnecessarily burden the free trading of those allowances? Does this open the door for "special interests" to exert undue influence over the process?

10. What is the purpose in defining an "allowance" as an authorization to emit a ton of SO2 or NOx during a "specified calendar year, when allowances are otherwise designed to be banked and carried forward for use in subsequent years?

11. Why does the bill in Section 404(c)(2) state that it is unlawful for a source "or unit" to emit sulfur dioxide in excess of its allowable emission rate? However, the bill also allows a "source" to exceed its allowable rate if it purchases the necessary allowances. Thus, isn't Section 404(c)(2) inaccurate?

12. Section 403(a) -- one of the provisions dealing with allowances -- states that if an existing source is removed from commercial operation, the annual allocation of allowances shall continue to be issued "for each five year period," in accordance with the schedule for issuance of permits. Why does the bill make reference to a five-year allowance allotment cycle in this context?

13. Does EPA have any estimate as to the costs to various sources for the additional 2% control requirement created by the Administrator's 2% reserve (Section 403(a)(2)(A))? Does it mean that a full compliance plan from a utility will be answered with only 98% of the allowances that utility will need? How do they overcome this shortfall?

14. Allowance transfers are not effective until received and "recorded" by the Administrator. (Section 403(a)(2)(A)) What is to prevent the Administrator from refusing to record an allowance transfer?

15. Section 405(b), which deals with compliance during Phase II, seems to imply that affected units that obtain allowances will still be out of compliance. Is that the intent of the language and, if so, wouldn't this run contrary to the whole idea of emissions trading?

16. S. 1630 alters the program timing of S. 1490 by pushing forward twelve months the Phase I and Phase II SO2 emission control deadlines from December 31, 1995, and December 31, 2000, to January 1, 1995, and January 1, 2000, respectively.

    a. If the bill passes this year, the Phase I compliance deadline will be just over four years away. Don't you foresee the need for a longer compliance deadline simply because vendors and manufacturers of control equipment will not be able to meet demand?

    b. How long does it take to install a scrubber.

    c. How many units across the country will have to be offline at the same time during the construction of scrubbers? What are the implications for energy supplies and cost?

    d. Do you support the compliance deadlines of December 31, 1995, for Phase I, and December 31, 2000, as contained in the proposal the President sent to Congress last year (S. 1490)?

    e. In a briefing to Senate staffers, the staff of the Senate Committee on the Environment and Public Works stated that the move-up was achievable. Do you agree?

    f. At no time in the history of this country have so many environmental control projects been undertaken simultaneously. Do you see the response from control vendors adequate and timely? In light of the profound decline in this industry in the last decade?

17. The cost of implementing this proposed acid rain control measure has been estimated to be as much as $5 billion annually, yet this expenditure will only accelerate today's on-going SO2 decreases already mandated by the existing Clean Air Act. In light of NAPAP's pronouncement that there is no impending acid rain crisis,

how can we justify such a high cost for merely accelerating the progress we are and will make in lowering total emissions of SO2?

18. In recent years we have begun to acknowledge our eroding position among other industrialized nations. How will this bill affect the international competitiveness of electricity-intense industries in our country vis-a-vis the majority of the industrialized countries that are not employing such strict controls?

19. Did the Agency determine the impact of the acid rain titles in S. 1490 and S. 1630 on the possible shifting of coal supplies, that is, from high to low sulfur coal and from the East to the West, and the possible dislocation of mining jobs? If so, please share with us the results of your study.

20. Isn't the triple enforcement hit excessive? The bill requires sources to pay an excess emissions fee of 2,000 dollars a ton, requires them to offset exceedences with succeeding year reduction (the offset requirement could be indefinite), and make each ton a separate violation (current penalty is up to $25,000 per violation per day).

21. Is there going to be any real effect from the removal of the percentage reduction requirement as contained in S. 1630? EPA is employing a "top-down" BACT approach which will guarantee that all new major sources and modifications will likely face scrubbers.

22. S. 1630 defines a "Clean State" as one which more than 50% of its emissions are controlled by a "technological system of continuous emission control." The current Clean Air Act defines that phrase (Section 111(a)(7) of the current Act) to include technologies other than scrubbers, such as precombustion fuel cleaning. Thus, to qualify for the Clean States exemption a state could have no scrubbers in place. Is this correct? What is the level of scrubbing in the states qualifying for the exemption?

Clean Coal Technologies

1. S. 1630 does not contain compliance date extensions for clean coal technologies as in the Administration's proposal.

    a. Does the panel support the addition of such a provision to the bill?

    b. What should be the criteria used to establish eligibility for such compliance date extensions?

2. The Administration's bill is limited to repowering technologies.

    a. What other types of clean coal technologies are currently being funded by the Administration?

    b. Should these other technologies should be eligible for such compliance date extensions? If not, why not?

3. As an incentive, S. 1630 extends the compliance date for Phase II (2000) sulfur dioxide requirements for existing units which propose to meet those requirements by repowering with clean coal technologies (CCT). By limiting, however, the compliance date extension to units which "repower" with Clean Coal Technology, the bill fails to recognize sulfur reduction technologies that do not involve repowering which DOE is supporting through the CCT program. Is this limitation justified in your opinion? How much money is being spent by DOE on these excluded clean coal technologies?

Air Toxics

1. S. 1630 does not include a provision found in the Administration's bill that requires a three year study before utilities are regulated under the air toxics title.
   a. Does the Administration support the 3-year study of utility emissions before mandating toxic emission controls for utilities, as stated in the President's proposed legislation?
   b. What impact will the air toxics provision of S. 1630 have on the utility industry? How does this impact compare with the President's proposal?
   c. What would be the requirement for MACT (Maximum available control technology) mean for an electric power plant, in general? And what would it mean for power plant that already has a scrubber installed?
   d. What data currently is available to support the need for additional regulation of this sort for power plants?
2. Section 112(d)(1) lists a number of possible controls which must be considered in setting "MACT" standards, including process changes and substitution of materials. Do you interpret this language as giving you the authority to force utility boilers to switch fuels, e.g., coal to gas?
3. In the case of control of toxic emissions, after controls are installed, if the risk assessment showed that there was a risk greater than a one in one million to exposed individuals what further actions beyond MACT would be required of power plants? Of industrial installations?
4. In the case of industrial installations, are the costs of controlling toxics likely to drive industries overseas?

   Won't the consumer ultimately pay these costs?
5. Coal contains trace amounts of chlorine, fluorine and other Table A substances which might trigger the 10/25 ton violation threshold for coal fired boilers. If the chlorine study provision (Section

112(e)(5)) was correct, why not a similar study provision for other pollutants, at least until we can quantify the cumulative impacts of acid rain, and any additional ozone related NOx controls before we impose new air toxic controls?

6. Section 112(e)(1)(A) requires that MACT controls be set for sources of cadmium and twelve other pollutants within two years of enactment. Many utility boilers may trigger the threshold for cadmium and thus would be subject to regulation. Why control utility boilers so soon in the process when many of them will face acid rain and NOx controls under other provisions of the Act?

7. Does the Administration have information on the number of facilities which might have to be shut down to meet the one in ten-thousand risk level, or the one in a million risk level, as stated in Title III?

8. Section 112(d)(2) allows the Administrator to prohibit emissions "where achievable". Since zero emissions are always technically achievable e.g., shutdown, what criteria will be used to determine whether EPA imposes an absolute prohibition on emissions as opposed to the imposition of technological controls? Would EPA oppose language which states that all elements of a decision, cost, environmental impacts, energy requirements are to be given "equal" weight?

9. From several sources of literature, to include the EPA last March, I find a consensus that air quality in this country has improved:

Lead	down	88%
Carbon monoxide	down	32%
Sulfur dioxide	down	35%
Ambient ground level ozone	down	16%
Nitrogen dioxide	down	12%
Annual average particulate matter	down	21%

And I keep hearing how this Clean Air Act amendment will improve national health and reduce related health care costs. But I note just the opposite. All the quantities noted earlier are down from 1978 levels yet I see increases in health care costs and no detectable change whatsoever in lifespans, quality of life, or the premature death rate. Why not?

Why should I support legislation calling for expensive, further reductions in a program that is already working based on EPA's findings but is not paying the health care dividends that we were lead to believe would be there? Is emotion tricking us again?

Oxygenated Fuels

1. The Senate Environment and Public Works Committee Reported bill would require all 44 carbon monoxide nonattainment areas to implement an oxygenated fuels program containing a minimum of 3.1 percent oxygen. Since ethanol is the only fuel in widespread

commerce that can meet the 3.1 percent requirement, S. 1630 also has a so-called oxygen credits trading program. As I understand the effect of this provision, however, it would result in a minimum of a 45-50 percent set aside for ethanol in those 44 carbon monoxide nonattainment areas. Could you tell me what the Administration's position is on the oxygenated fuels provision in S. 1630 and how the Administration's bill approaches this issue?

Costs

1. Has your Department done a nationwide or a state-by-state cost analysis of each of the Titles of S. 1630 and S. 1490? If so, what are the results, title by title, and how do they compare with the Business Roundtable results released this past week? Please, also, explain if you can the reasons for any differences in the numbers.

Questions for DOE and EPA from Senator Murkowski

Clean Air Hearing January 24, 1990

QUESTIONS:

1. TO WHAT EXTENT DOES THE ACID RAIN REDUCTION PROGRAM PROMOTE AND FACILITATE THE USE OF LOW SULFUR COAL?

2. I HAVE SEEN IN THE COMMITTEE REPORT THAT ALASKA IS EXEMPTED FROM PHASE II OF THE ACID RAIN PROGRAM. IS IT YOUR UNDERSTANDING THAT PHASE II ONLY APPLIES TO THE 48 CONTIGUOUS STATES?

3. THE SENATE BILL SPECIFICALLY LISTS CLEAN COAL TECHNOLOGIES THAT WILL QUALIFY A UTILITY FOR AN EXTENTION OF THEIR EMISSION REDUCTION OBLIGATION.
WHY IS THAT?
WHAT ABOUT CLEAN COAL TECHNOLOGIES THAT HAVE QUALIFIED FOR DEPT. OF ENERGY GRANTS BUT ARE NOT ON THIS LIST?

Malcolm Wallop

QUESTIONS FROM SENATOR MALCOLM WALLOP FOR CLEAN AIR HEARING

Mr. Rosenberg, EPA

1. Would you support an amendment to extend the compliance deadlines for acid rain emissions in 1995 and 2000 by one year? Would you support a two year extension for the deadlines?

Department of Energy
Washington, DC 20585

August 6, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural
Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On January 24th and 25th, 1990, Deputy Under Secretary Linda G. Stuntz gave testimony on S. 1630, the Clean Air Act, before your committee.

Following that hearing, you submitted written questions on behalf of yourself, Senator Wendell H. Ford, Senator James A. McClure, Senator Frank H. Murkowski and Senator Malcolm Wallop to supplement the record.

Enclosed are the answers to those questions, which also have been sent to Senators Ford, McClure, Murkowski and Wallop. Please note that the answers to these questions reflect the date of the hearing.

If you have any questions, please have your staff call Renee Wilhite at 586-4277. She will be happy to assist you.

Sincerely,

Jacqueline Knox Brown

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental Affairs

Enclosures

U. S. DEPARTMENT OF ENERGY
Responses to Post-Hearing Questions
from the
Committee on Energy and Natural Resources
UNITED STATES SENATE

QUESTIONS FROM SENATOR McCLURE

Question 1: There does not appear to be any economic justification for the trading ratios of 1 1/2 NOx for 1 SOx (Section 403(c)). It seems to be an arbitrary assumption. Can you provide us with the technical basis for such a ratio?

Answer: The appropriate way to make an equivalency ratio would be to calculate the cost of environmental impacts of a pound of each pollutant and to use the ratio of those costs. However, the state of science on calculating those costs is far too primitive to allow such a calculation. The approach used was to ratio the weight of each compound which would react with one hydronium ion. The calculation is somewhat involved:

- NOx is emitted predominately as NO, and rapidly oxidizes in the atmosphere to NO2. To facilitate consistent measurement, regulations specify that the weight of all the nitrogen oxide species emitted will be expressed as NO2 [e.g., 40 CFR 60.44(a)]. Hence, the remainder of this discussion will refer to NOx as though it is NO2.
- Power plants emit sulfur compounds almost entirely as SO2, and regulations specify that emissions will be expressed as SO2.
- Chemists measure acidity in terms of the relative concentration of hydronium ions.

The greater the concentration, the greater the acidity. The weight of reactants in a reaction is discussed in terms of "pound moles" of a compound.

- One molecule of NO2, upon reaction, yields one hydronium ion. Because the molecular weight of NO2 is 46, 46 pounds of NO2 will yield one pound mole of hydronium ions. One molecule of SO2, upon reaction, yields two hydronium ions. The molecular weight of SO2 is 64, so 32 pounds of SO2 will yield one pound mole of hydronium ions.
- Hence, either 32 pounds of SO2 or 46 pounds of NOx will yield the same amount of hydronium ions or acidity. The ratio of these compounds is 46/32 or 1.44.

The primary shortcoming of using this "acidity" approach to establishing relative values for controlling these two pollutants is that they have many effects which are not directly related to acidity. Additionally, the chemistry of the environment is more complicated than the simple explanation offered above, so even the equivalent acidity approach is approximate. As a result, the trading ratio used is simply 1.5 to 1.

QUESTIONS FROM SENATOR McCLURE

Question 2: In crafting the allowance and permit provisions in the acid rain titles of S. 1490 and S. 1630, did your Department give consideration to the "real world" impact this marketing and trading system between utilities would:

Question 2(a): Have on electricity reliability in various regions of the country, particularly those regions experiencing rapid growth?

Answer: The Department of Energy believes that the allowance trading system is workable in the "real world" and will help provide appropriate economic and environmental incentives for (1) the efficient use of existing capacity, (2) the construction of needed generation and transmission facilities, and (3) the efficient consumption of electricity.

We believe that a sufficient quantity of marketable allowances will be available to enable all regions to build adequate capacity and to maintain adequate reliability levels. Utilities in high-growth regions may construct and use low-emission sources, such as clean coal technologies, gas-fired combined cycle, renewables (including hydro and solar), and nuclear. The need for additional generating capacity also can be addressed through improved end-use efficiency and conservation.

To the extent utilities in high-growth regions or elsewhere need to acquire emission allowances for new sources, those

Answer 2(a) (continued):

allowances may be acquired from anywhere in the country. In addition to purchases of allowances, utilities may use numerous creative planning and market arrangements to obtain allowances, including engaging in staggered term leasing of allowances, contracting to pay directly for emissions controls at units owner by other utilities, or retiring existing high-emission units.

Question 2(b): Have on the possible increase of imported oil or imported power as an alternative means to comply with the mandated SO_2 and NO_x emissions reductions? If so, please share with us the result of your analysis.

Answer: The President's acid rain proposal should result in reduced utility oil consumption. The EPA/ICF analysis of S. 1490 indicates that in the year 2010, annual utility oil consumption would drop by two-thirds (approximately 1 quad, or 160-170 million barrels) due to the effects of acid rain legislation.

In 1988, the New England, Mid-Atlantic, and South Atlantic (primarily Florida) census divisions accounted for over 84 percent of utility oil consumption, of which over 93 percent was residual fuel oil. The bulk (77 percent) of residual fuel oil used in this region (Petroleum Administration Defense District I (PADD I)) was imported. Thus, lower utility oil consumption in PADD I is expected to result in lower consumption of imported residual fuel oil.

Answer 2(b)
(continued):

DOE has not explicitly modelled the effects of acid rain legislation on electricity imports from Canada. EIA has projected that net electricity imports in 2000 will be approximately 60 billion KWH without any new acid rain legislation, up from 31.8 billion KWH in 1988.

To the extent that S. 1490 or S. 1630 will raise the cost of coal-fired electricity, power imports from Canada may increase to regions that currently generate the majority of their electricity with coal, but only to the extent that transmission capacity is available and is not sufficiently costly to make Canadian electricity uncompetitive. Currently, nearly all Canadian electricity exports go the Northeast and West Coast (approximately two-thirds and one-third, respectively), regions that produce most of their electricity from non-coal sources (predominantly hydro and oil). Imports by Ohio Valley utilities may be constrained by the cost of long distance transmission capacity limitations. In addition, it is uncertain how much more electricity capacity Canadian authorities will be willing to commit to the U.S.

QUESTIONS FROM SENATOR McCLURE

Question 3: The need for further reductions in the emission of NOx to control acid rain is more uncertain than the need for sulfur dioxide (SO2) reductions. Nevertheless, S. 1630 contains NOx reduction requirements of 4 million tons, far in excess of S. 1490 goal (2 million tons) -- requirements that could drastically increase the price tag of further acid rain controls by requiring the use of expensive selective catalytic reduction devices in some cases, in addition to low-NOx burners.

Question 3(a): Do you support the President's NOx 2 million tons of reductions or the Environment Committee's stringent 4 million tons? What study recommends such a change?

Answer: The Department of Energy supports the President's approach to NOx control. The Administration's bill is based on requiring the use of cost effective low NOx burners on coal fired units capable of being retrofit with such burners. The Administration did not support the NOx provisions in Title IV of S. 1630, as proposed, because they required appreciably greater reductions, which, in turn, required control equipment that is much more expensive than low NOx burners. The Administration fully supports, however, the NOx reduction requirements in Title IV of S. 1630, as adopted by the Senate on April 3, 1990.

We are not aware of what study or other analysis led the drafters of the original S. 1630 to change the stringency of NOx control set forth in the Administration's bill.

Question 3(b): Do you contemplate utilities using selective catalytic reduction (SCR) technology to meet this 4 million target? If not, what technology? (Low NOx burners will not meet this objective based on actual operating data.)

Answer: SCR is certainly one option which utilities could have selected in order to comply with S. 1630, as proposed. However, we believe it would have been less expensive for utilities to achieve further reductions of SO2 and use the trading provisions in Section 403(c) to achieve the NOx reduction required. Alternatively, utilities could have turned to advanced technologies which reduce both SO2 or NOx, such as repowering technologies, or abatement processes which simultaneously remove both pollutants, or to advanced NOx reduction processes, like reburning.

Given that the adopted bill replaced the reduction goal with one consistent with the Administration's bill, we believe that the stringent controls associated with S. 1630, as proposed, will not be necessary.

Question 3(c): If we accept your assumption that NOx must be controlled so stringently in order to "protect the environment" as you state, why aren't all potential sources controlled -- for example, industrial sources?

Answer: We do not know the rationale behind the language originally proposed in S. 1630. The language adopted by the Senate has a very rational basis: coal-fired utilities are required to install cost-effective NOx control technologies in a timely manner.

QUESTIONS FROM SENATOR McCLURE

Question 4: The Committee bill rejects the President's approach of encouraging the use of low NOx burner (LNB) technology to reduce NOx emissions and, instead, requires specific numerical reductions that may well be unreachable without resort to selective catalytic reduction (SCR) technology.

Question 4(a): Is there any scientific basis for setting such ambitious NOx reduction requirements?

Answer: Acid rain legislation, like most environmental legislation, must balance environmental goals and the cost of achieving those goals. We cannot afford to live in a risk-free world. The President's bill provides a reasonable balance between costs and goals. We are unaware of any environmental effects studies which would justify the cost of the additional requirements in S. 1630, as proposed. We are pleased to note that the Senate saw fit to amend the language regarding NOx in S. 1630, and that the adopted bill is much closer to the Administration's position.

Question 4(b): Do we know how much the additional cost of this bill will be as a result of this NOx reduction approach?

Answer: We do not know, but we have estimates of the additional cost of NOx control in S. 1630, as initially proposed. Relative to the Administration's proposal, DOE estimates that the additional NOx control requirement under S. 1630 totals about 1.2 million TPY. We believe that the least cost approach to achieving this reduction would be to reduce SO2 according to the ratio set forth in Section 403(c), which is 1.5:1. This implies a further reduction of 800,000 TPY of SO2. Using the rule of thumb that an additional 2 million TPY of reductions double costs, we estimate that an additional 0.8 million TPY would increase costs about 30-40%, or roughly $1 billion per year. We estimate that the NOx control requirements in Title IV of S. 1630, as adopted by the Senate, will be approximately equal to the NOx controls set forth in the Administration's proposal.

Question 4(c): Finally, since SCR utilizes ammonia and ammonia is covered in the toxic title - don't we have a conflict?

Answer: There is a potential conflict. When SCR is operated at extremely high levels of efficiency (over 80% control), ammonia injection levels must be monitored and controlled very carefully to avoid "ammonia slip", or the emission of unconverted ammonia from the smokestack. As noted above, however, the version of S. 1630 adopted by the Senate replaced the provisions requiring extremely large emission reductions with provisions which are not expected to lead to use of SCR.

QUESTIONS FROM SENATOR McCLURE

Question 5:	If recordation of allowance transfers is intended to be simply a pro forma step, why doesn't the bill promote certainty in the trading market by providing for automatic recordation of allowances within a specific period of days or weeks? Doesn't the risk of bureaucratic delay in recording allowance transfers unnecessarily burden the free trading of these allowances? Does this open the door for "special interests" to exert undue influence over the process?
Answer:	Both the Administration's bill, S.1490, and the Senate Committee on Environment and Public Work's bill, S. 1630, make provision for the Administrator of the Environmental Protection Agency (EPA) to issue regulations, within 18 months of enactment, on the issuance, transfer, and use of allowances (see section 503(b) of S. 1490 and section 403(b) of S. 1630). Both bills have a specific provision dealing with an allowance tracking system (see section 503(b) of S. 1490 and section 403(d) of S. 1630). Both bill's allowance tracking provision requires the Administrator of the EPA to institute an allowance tracking system for the recordation of allowances. The Senate bill's provision is somewhat more explicit in that it requires the Administrator to implement the tracking system within 18 months of enactment. Automatic recordation of allowances certainly is one way to implement the tracking system and is an option that the Administrator of the EPA should consider. However, providing the Administrator of the EPA the general mandate to administer the allowance trading system is the most

Answer 5 (continued):

flexible and efficient way to implement the allowance trading system. The record is clear from Committee testimony, that the EPA will implement a straightforward tracking system keeping it as simple as possible. Additional legislative direction will merely make the allowance tracking system more cumbersome and less market-sensitive.

QUESTIONS FROM SENATOR McCLURE

Question 6:	What is the purpose in defining an "allowance" as an authorization to emit a ton of SO_2 or NO_x during a "specified calendar year", when allowances are otherwise designed to be banked and carried forward for use in subsequent years?
Answer:	Allowances will be issued yearly for several reasons. Yearly issuance provides liquidity to the marketplace. Yearly issuance makes it easier to keep track of allowances rather than having allowances issued indefinitely requiring that they be divided and subdivided over time. Yearly issuance makes the administration of the allowance reserve more manageable since it permits sales on a yearly basis in place of selling a subdivided portion of each allowance. Even with banking and allowing for carryovers to ensuing years, administratively it will be easier to keep track of a yearly allowance than a portion of an allowance that is issued only once. Thus, yearly issuance uncomplicates the allowance trading system and makes its administration much easier.

QUESTIONS FROM SENATOR McCLURE

Question 7:	Section 405(b), which deals with compliance during Phase II, seems to imply that affected units that obtain allowances will still be out of compliance. Is that the intent of the language and, if so, wouldn't this run contrary to the whole idea of emissions trading?
Answer:	Section 405(b) provides that it will be unlawful for units that are 75 MW or greater and that have SO_2 emissions equal to or greater than 1.2 lbs/mmBTU to emit more than the unit's baseline multiplied by an emission rate equal to 1.2 lbs/mmBTU, divided by 2000, unless the unit has allowances equal to the emissions that exceed those permitted by this subsection. It is clear from this subsection (and from a similar subsection in the Administration's bill, see section 505(b)) that the unit can emit only the lawful standard unless it obtains allowances for any emissions above the standard. As long as the unit has met the standard or has the requisite number of allowances it will be in compliance.

QUESTIONS FROM SENATOR McCLURE

Question 8: S. 1630 alters the program timing of S. 1490 by pushing forward twelve months the Phase I and Phase II SO2 emission control deadlines from December 31, 1995, and December 31, 2000, to January 1, 1995, and January 1, 2000, respectively.

Question 8(a): If the bill passes this year, the Phase I compliance deadline will be just over four years away. Don't you foresee the need for a longer compliance deadline simply because vendors and manufacturers of control equipment will not be able to meet demand?

Answer: Our analyses indicate that the least cost control approach in Phase I for most utilities will be switching from higher sulfur coal to lower sulfur coal, not installation of scrubbers. Hence, we do not foresee deliverability problems in Phase I. If scrubbers were in great demand, however, the four year lead time in S. 1630 would be extremely tight, as discussed below.

Question 8(b): How long does it take to install a scrubber?

Answer: Utilities will need a certain amount of time to decide how they want to comply with the legislation. The allowance trading provisions in both S. 1490 and S. 1630 offer significant opportunities for cost savings for the astute utility, but evaluation of alternatives facing the utility will require time. Moreover, the wise utility would discuss these options with its regulatory commission and state environmental agency. Where a utility operates in only one state, this process might be completed in a year. For multi-state utilities, the process could take the form of a protracted negotiation, and require longer.

We estimate that the period from contract award to startup will be about 3-4 years.[1] Assuming one year for the utility decision-making process, that implies a 4-5 year period for the entire process.

Question 8(c): How many units across the country will have to be offline at the same time during the construction of scrubbers? What are the implications for energy supplies and cost?

Answer: Different groups estimate different levels of scrubbing capacity under the proposed legislation. In their analysis for EPA, ICF, Inc., estimated about 15-30 GW of retrofit technology would be installed, depending on a number of alternative assumptions.[2] At the other extreme, the analysis conducted for the Edison Electric Institute projected 60-75 GW of additional scrubbers and other technological controls.[3] Coal generating capacity in the U.S. is projected to be about 315 GW in 2000 (out of a total generating capacity of about 750 GW). Hence, the scrubbed capacity, as a fraction of total capacity is about 2-10%, depending on the amount of capacity you think will be scrubbed due to the legislation.

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[1] Assessment of Vendor Capabilities To Supply FGD Systems for Proposed Acid Rain Reduction, PEI Associates, Inc., USDOE Contract No. DE-AC01-88 FE61024, 9/89, p.20.

[2] Economic Analysis of Title V of the Administration's Proposed Clean Air Act Amendments (H.R. 3030/S. 1490), USEPA/ICF Resources Inc., 9/89, Tables A-12 and B-12.

Local impacts will be much higher in some states. For example, ICF's estimates, which are about 1/4 of TBS's, indicate that one-sixth of the capacity in Ohio and Pennsylvania will be retrofit with scrubbers. If all of these units are offline at the same time, the utilities could have difficulty meeting demand, even under ICF's modeling approach.

We do not have definitive estimates of what it will cost to avoid supply shortages due to units being offline simultaneously for scrubber retrofit. One obvious solution would be to retrofit the unit before necessary. The capital cost of retrofit scrubbers tends to be about 3-6 mills per kilowatt-hour, depending largely on the boiler size and the degree of difficulty in retrofit. An existing generating unit, for which the original capital costs have been significantly depreciated, might cost about 15 - 25 mills per kilowatt-hour. Hence, retrofitting the unit "early" could increase its power costs by 12 - 40%. The price of electricity from the overall utility system would not be expected to increase by that amount.

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[3] Economic Evaluation of H.R. 3030/S. 1490 "Clean Air Act Amendments of 1989", Edison Electric Institute/Temple, Barker & Sloane, Inc., 8/89.

The need for such "early" compliance would be totally dependent upon the size of the utility and the portion of its capacity that required retrofitting. The hookup time for a scrubber might be two months, and this could come at very little disruption to the system if the two months were scheduled during slack periods of demand, like Spring or Fall. The extent of the timing issue at a given utility will therefore depend on whether it has sufficient excess capacity in the Spring or Fall to take all retrofitted units offline, and still be able to meet electricity demand requirements. Otherwise the utility will likely retrofit some of the units earlier than required by law. Another alternative would be to purchase power from another system during the "peak" scrubber construction years. Clearly, this approach has limits if most utilities in the region are also heavily involved in retrofitting hardware.

Question 8(d): **Do you support the compliance deadlines of December 31, 1995, for Phase I, and December 31, 2000, as contained in the proposal the President sent to Congress last year (S. 1490)?**

Answer: Yes.

Question 8(e): **In a briefing to Senate staffers, the staff of the Senate Committee on the Environment and Public Works stated that the move-up was achievable. Do you agree?**

Answer: I assume that by "move-up" you are referring to the modified compliance dates established under S. 1630, i.e., January 1, 1995 and January 1, 2000. These earlier compliance dates are technically achievable. The earlier date for Phase I is of little consequence, because the primary method of compliance in Phase I is expected to be overwhelmingly dominated by use of low sulfur coal. No new technology or extended compliance date is needed to switch to lower sulfur coal. The 2000 compliance date is more problematical. Although technically achievable, the sooner the requirement, the less time available for emerging technologies, such as advanced scrubbers, to prove their commercial availability. Selection of this earlier compliance date requires a careful balancing of environmental benefits and compliance costs.

Question 8(f): **At no time in the history of this country have so many environmental control projects been undertaken simultaneously. Do you see the response from control vendors adequate and timely? In light of the profound decline in this industry in the last decade?**

Answer: The Department believes that several years are necessary for response by hardware manufacturers. The Phase I requirements, scheduled for compliance in 1995 might pose a supply problem, but the primary reliance of utilities on low sulfur coal in Phase I means that scrubber vendors should be able to meet expected demand without undue strain. The year 2000 requirements are expected to lead to much more scrubber use than Phase I, but there is adequate time for equipment vendors to respond to this demand. There is, nevertheless, a potential for bottlenecks. The singular compliance date implies that most utilities planning to purchase hardware for compliance will be going through the same steps at the same time (planning, design, manufacture, field construction). However, the fact that this problem has already been identified will likely lead to planning which would largely mitigate any adverse effects on hardware availability.

QUESTIONS FROM SENATOR McCLURE

Question 9: The cost of implementing this proposed acid rain control measure has been estimated to be as much as $5 billion annually, yet this expenditure will only accelerate today's on-going SO2 decreases already mandated by the existing Clean Air Act. In light of NAPAP's pronouncement that there is no impending acid rain crisis, how can we justify such a high cost for merely accelerating the progress we are and will make in lowering total emissions of SO2?

Answer: While the Department believes that some environmental improvement would occur absent additional legislation, via replacement of older plants with newer and cleaner plants, this process lacks certainty and would require much more time than explicit legislative and regulatory requirements. The President has decided that the need for more definite and nearer term emission reductions is real and that the costs of these reductions are reasonable.

QUESTIONS FROM SENATOR McCLURE

Question 10: In recent years we have begun to acknowledge our eroding position among other industrialized nations. How will this bill affect the international competitiveness of electricity-intense industries in our country vis-a-vis the majority of the industrialized countries that are not employing such strict controls?

Answer: The acid rain provisions of S. 1490 and S. 1630 likely will have a small effect on the international competitiveness of electricity-intense industries. Nationwide, EPA/ICF has projected that S. 1490 will increase utility rates by an average of approximately 2.0 percent. Projected rate impacts in specific regions varied, however.

Electricity-intense manufacturing (e.g., primary aluminum, petroleum refining, chemicals, and paper products) are typically located in regions in which rate impacts are projected to be small. Rates in Washington and Oregon, a region replete with many energy intensive industries such as aluminum smelting and paper manufacturing, are projected to increase less than 1.0 percent by 2005. Rates in neighboring Idaho are projected to remain unaffected. Rate increases in Texas and Louisiana, states with an abundance of petrochemical plants, are projected to increase approximately 1.0 percent. Rates in Michigan, a state with much heavy manufacturing, are also projected to increase by less than 1.0 percent.

Answer 10 (continued):

Although average rates in many Midwest industrial states are projected to increase 2.0 percent to 5.5 percent by 2005, average rate increases are not necessarily indicative of rate increases for specific customer classes. Rate increase for electricity-intense industrial customers may be much lower than the average.

U.S. industrial electricity prices in 1985 were as low as $0.020/kwh for industrial inorganic chemicals, and $0.033/kwh for paper mills in the West Census Region. (EIA, Manufacturing Energy Consumption Survey: Changes in Energy Efficiency 1980-1985, DOE/EIA-0516(85).) Average industrial rates per kilowatthour were $0.048 in the U.S. in 1988, compared with $0.089 in West Germany and $0.146 in Japan. (EIA, Manufacturing Energy Consumption Survey: Consumption of Energy, 1985, DOE/EIA-0512(85).)

Moreover, in the past decade, many U.S. firms have refined their production processes and improved their energy efficiency. Between 1980 and 1985, energy intensive manufacturing industry groups improved efficiency by 17 percent (as measured by British thermal units per constant (1980) dollar value shipments). (EIA, Manufacturing Energy Consumption Survey: Changes in Energy Efficiency 1980-1985, DOE/EIA-0516(85).)

Answer 10 (continued):

The air toxics provisions of S. 1630, as initially proposed, will affect substantially more utility power plants and result in significantly higher compliance costs than S.1490. S. 1630, as initially proposed, will result, therefore, in higher utility rates in nearly all regions and may affect some industries adversely.

QUESTIONS FROM SENATOR McCLURE

Question 11:	Did the Department determine the impact of the acid rain titles in S. 1490 and S. 1630 on the possible shifting of coal supplies, that is, from high to low sulfur coal and from the East to the West, and the possible dislocation of mining jobs? If so, please share with us the results of your study.
Answer:	The Department has not modeled the coal related impacts associated with the precise requirements of the Administration bill. However, we believe that the results obtained by ICF Resources, Inc., for the Environmental Protection Agency are reasonable. This analysis indicated a reduction of about 25% in Northern Appalachian coal production in the year 2000, and 45% in coal production in the Midwest, relative to the level of production expected in the year 2000 without acid rain legislation. Decreases relative to current coal production would be smaller. The analysis showed a commensurate increase in coal production in other regions.[4] EPA/ICF estimated regional mining job dislocations associated with these coal production shifts to total about 7,000 mining jobs in Northern Appalachia, and 9,500 jobs in the Midwest.[5]

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[4] Op. cit., USEPA/ICF, Table A-9.

QUESTIONS FROM SENATOR McCLURE

Question 12: S. 1630 defines a "Clean State" as one which more than 50% of its emissions are controlled by a "technological system of continuous emission control." The current Clean Air Act defines that phrase (Section 111(a)(7) of the current Act) to include technologies other than scrubbers, such as precombustion fuel cleaning. Thus, to qualify for the Clean States exemption a state could have no scrubbers in place. Is this correct? What is the level of scrubbing in the states qualifying for the exemption?

Answer: Generally speaking, coal cleaning will not remove more than about 30-40% of the sulfur content of coal, and in some cases, the limit is much less. Amendment 1293 to S. 1630 (introduced on March 5) revised the approach to "Clean States", making your question relatively moot. In this substitute amendment, special provisions were provided for any state emitting at or below 0.8 #SO2/mmBtu (statewide average over all fossil fuel fired units) in 1985. Such states are permitted special allowance alternatives. No fixed percentage of scrubbing is included in the requirements in the revised language. Hence, states could, and do qualify for the "Clean States" provisions without having any scrubbing.

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[5] Op. cit., EPA/ICF. Table A-10.

QUESTIONS FROM SENATOR McCLURE

Question 1: S. 1630 does not contain compliance date extensions for clean coal technologies as in the Administration's proposal.

Question 1(a): Does the panel support the addition of such a provision to the bill?

Answer: The Department supports compliance date extensions for clean coal technologies as provided in the Administration's proposal, S. 1490.

Question 1(b): What should be the criteria used to establish eligibility for such compliance date extensions?

Answer: In determining what clean coal technologies warranted special regulatory treatment, the Administration was guided by two principles: (1) encourage cost effective technologies for the future that will not decrease boiler efficiency and will not generate toxic or difficult to dispose of sludge; and (2) those who take the risk of demonstrating new, environmentally superior technologies should not be penalized.

The use of technologies which are already available such as co-firing with natural gas, or which produce a sludge as do many current scrubber technologies, does not warrant extension of regulatory deadlines. To the extent promising technologies will not be able to be demonstrated commercially by the year 2000, regulatory flexibility may be warranted if those technologies meet cost-effectiveness, waste and efficiency criteria.

QUESTIONS FROM SENATOR McCLURE

Question 2: The Administration's bill is limited to repowering technologies.

Question 2(a): What other types of clean coal technologies are currently being funded by the Administration?

Answer: In addition to repowering technologies, the following types of clean coal technologies have been selected for negotiation and/or are receiving Federal funds:

- Coal Processing (coal preparation and fuel upgrading)
- Advanced Combustion (for retrofit of existing boilers)
- Flue Gas Cleanup (boiler/duct injection as well as stack gas cleanup)
- Industrial processes (e.g., steel and cement industry application)

Question 2(b): Should those other technologies be eligible for such compliance date extensions? If not, why not?

Answer: The Department does not believe that a compliance date extension is necessary for the above technologies. They are projected to be commercially available by the compliance date of December 31, 2000.

QUESTIONS FROM SENATOR McCLURE

Question 3: As an incentive, S. 1630 extends the compliance date for Phase II (2000) sulfur dioxide requirements for existing units which propose to meet those requirements by repowering with clean coal technologies (CCT). By limiting, however, the compliance date extension to units which "repower" with Clean Coal Technology, the bill fails to recognize sulfur reduction technologies that do not involve repowering which DOE is supporting through the CCT program. Is this limitation justified in your opinion? How much money is being spent by DOE on these excluded clean coal technologies?

Answer: Compliance date extension for repowering technologies is based on projections for when these technologies will reach the point of commercial readiness, i.e., when a sufficient data base exists to assure performance and cost requirements of the utility sector can be met. It is also based on the promise that repowering technologies offer to burn coal more efficiently (thus reducing CO2 emissions) and with less waste than other technologies.

Of the projects awarded to date, technologies not eligible for the three-year deadline extension are estimated to account for about $600 million of the $1.3 billion DOE share of the 39 projects selected to date.

Air Toxics

Question 1a: **S. 1630 does not include a provision found in the Administration's bill that requires a three year study before utilities are regulated under the air toxics title.**

a. Does the Administration support the 3-year study of utility emissions before mandating toxic emission controls for utilities, as stated in the President's proposed legislation?

Answer: The types, levels and variability of air toxics from electric utility boilers are not well characterized in available studies. The Administration supports carrying out a study to characterize the types and levels of pollutants, to determine the level of potential health hazard remaining after certain controls are used, and then to propose whether (1) the air toxic technology regulations (i.e., MACT), (2) no added regulation, or (3) specially designed regulations are needed to effectively reduce any remaining significant health hazards posed by electric utility emissions.

It should be noted that electric utilities already apply a number of controls that reduce the level of emissions of particulates and gases, including those that are listed as air toxics. For example, particulate controls on coal-fired units reduce aggregate particulate levels by more than 99% on many units.

QUESTIONS FROM SENATOR McCLURE

Question 1b:	What impact will the air toxics provision of S. 1630 have on the utility industry? How does this impact compare with the President's proposal?
Answer:	S. 1630, as initially proposed, would require controls be imposed unless the electric utility sector was not found to include major sources of air toxics. It is highly unlikely that coal-fired electric utility boilers would not be found to be a category that includes a major source. Therefore, all boilers that emit above a *de minimis* level (yet to be defined) would be required to add to present controls, new technology controls defined as MACT. Since present particulate controls for newer oil-fired and coal-fired plants often operate at removal levels of 99.5 percent or higher, this could result in much of the presently operating particulate emission equipment having to be upgraded or replaced. Further, control equipment to capture gaseous emissions, such as hydrochloric acid, might be required. This could result in flue gas scrubbing (not necessarily the same devices as for SO_2 removal). Note that although S. 1630 defers regulation of utility emissions of chlorine for three years, all other utility emissions of listed toxics could be regulated on the schedule set on S. 1630. S. 1630 would require regulations for 25 percent of major sources of air toxics be promulgated within three years.

Answer 1b
(continued):

These MACT controls would be added to existing and new units that are above a certain size, yet to be defined, so actual costs cannot be determined precisely at this time. However, these costs are likely to exceed a billion dollars annually and, if gaseous emissions control are required for most existing units, the cost could be in the range of several billion dollars annually.

QUESTIONS FROM SENATOR McCLURE

Question 1c: What would be the requirement for MACT (Maximum available control technology) mean for an electric power plant, in general? and what would it mean for a power plant that already has a scrubber installed?

Answer: MACT for control of most air toxic particulates based on today's technology would be something such as ultrahigh efficiency electrostatic precipitators (ESP) or fabric filters (bag houses) operating at efficiency levels of 99.5 percent or higher for general particulate removal. These efficiencies are presently required for units that must meet the 1979 New Source Performance Standard (NSPS). It is possible that, for a specific air toxic particulate such as mercury, there may be an additional MACT requirement for control equipment specific to capture that type of particulate emission.

It is less likely, but possible, that MACT may be required for gaseous emissions such as hydrochloric acid or volatized mercury. If this occurs, a flue gas scrubbing technology may be required.

Thus for an existing power plant, MACT could result in:

- an added or upgraded ESP or fabric filter
- an addition of a flue gas scrubber (not necessarily an SO_2 scrubber), plus

Answer 1(c)
(continued):

- possibly, added controls for one or more specific pollutant(s) not sufficiently controlled by these more general purpose controls.

For a power plant already fitted with a SO_2 scrubber and with highly efficient particulate control equipment, it is possible no further controls would be needed or that controls for one of more specific pollutant(s) will be required.

Question 1d:	What data currently is available to support the need for additional regulation of this sort for power plants?
Answer:	General emissions data were compiled in: (1) a Radian Corporation 1986 report; and (2) a Canadian monitoring study of different coals burned in a boiler with particulate controls but no SO_2 controls.

These studies are:

- "Summary of Trace Emissions From, and Recommendations of Risk Assessment Methodologies for Coal and Oil Combustion Sources," R.C. Mead, et. al., Radian Corporation, 1986.
- "Characterization of Trace Constituents at Canadian Coal-Fired Power Plants," prepared for the Canadian Electrical Association by Pacific Northwest Laboratory and Brigham Young University, 1985.

The studies represent screening analyses but, as is stated in the Radian report, are insufficient to support rulemaking concerning powerplant toxic emission controls.

QUESTIONS FROM SENATOR McCLURE

Question 2: In the case of control of toxic emissions, after controls are installed, if the risk assessment showed that there was a risk greater than a one in one million to exposed individuals what further actions beyond MACT would be required of power plants? Of industrial installations?

Answer: In S. 1630, as initially proposed, for any source that has a risk to the maximum exposed individual of greater than one in a million after MACT has been installed, the source will be required to add improved technology and operating practices to reduce its air toxic emissions as a condition to renewing its operating permit. Permit renewal is required every five years. This would continue until a risk level below one in one million is achieved by the source. Due to timing included in S. 1630, the first such requirement beyond MACT for an upgraded permit condition would not occur until after 2000.

The S. 1490 requirement for a plant having residual cancer risk after MACT of greater than one in one million for the most exposed individual is less prescriptive than S. 1630, as initially proposed. Seven years after promulgation of MACT for a category, the EPA Administrator is evaluate the residual risks to human health after application of MACT. If the Administrator finds that the risk represents an unreasonable risk to public health taking into account cost and technical feasibility as well as the health risk, the Administrator is to promulgate further controls within two years to protect adequately against the risk.

QUESTIONS FROM SENATOR McCLURE

Question 3:	In the case of industrial installations, are the costs of controlling toxics likely to drive industries overseas? Won't the consumer ultimately pay these costs?
Answer:	For industrial facilities, MACT requirements will raise costs unless the facility has already incorporated a technology that is considered MACT. The actual level of cost is not now known and, based on the air toxic species to be reduced, could be a small or a large added cost. For some industrial units, it is possible that their products would become noncompetitive if the added costs were passed through to the customer.

If such is the case, the operator will need to reduce the product price by reducing the profit margin or would stop producing the product. If the facility stops producing the product (or goes out of business) the product would be produced at another unit, which may be a domestic or an overseas facility. In all probability, the cost to the consumer will be increased in either case.

The Administration has estimated the costs of S. 1630, as initially proposed, in the year 2003 for industrial sources to be $875 million to $3.5 billion for MACT. These would be additional costs for all stationary sources associated with residual risk regulation that are estimated as about $6 billion dollars by EPA. Estimated job losses of 10-14

Answer 3 (continued):

thousand are associated with plant closings due to residual risk.

Question 4: Coal contains trace amounts of chlorine, fluorine and other Table A substances which might trigger the 10/25 ton violation threshold for coal fired boilers. If the chlorine study provision (Section 112(e)(5)) was correct, why not a similar study provision for other pollutants, at least until we can quantify the cumulative impacts of acid rain, and any additional ozone related NO_x controls before we impose new air toxic controls?

Answer: The Administration supports a general study for all air toxic emissions from electric utilities before regulation is imposed. This study is necessary to determine whether MACT controls or some other specially designed controls should be used to further control emissions especially in light of the controls imposed by other parts of the bill.

QUESTIONS FROM SENATOR McCLURE

Question 5:	Does the Administration have information on the number of facilities which might have to be shut down to meet the one in ten-thousand risk level, or the one in a million risk level, as stated in Title III?
Answer:	EPA has estimated ten to fourteen thousand job losses in facilities that may not be able to meet the one in ten thousand risk level, and thus may be shut down. The affected industries are chemical plants and coke oven facilities. For the one in one million standard under S. 1630, if the plant employs all available technology and operating practices to minimize emissions, the plant, at the discretion of the EPA Administrator, can continue to operate by periodically receiving temporary operating extensions for an indefinite period.

QUESTIONS FROM SENATOR McCLURE

Question 6: Section 112(d)(2) allows the Administrator to prohibit emissions "where achievable." Since zero emissions are always technically achievable, e.g., shutdown, what criteria will be used to determine whether EPA imposes an absolute prohibition on emissions as opposed to the imposition of technological controls? Would EPA oppose language which states that all elements of a decision, cost, environmental impacts, energy requirements are to be given "equal" weight?

Answer: In section 112(d)(2), the facility is meant to operate at the lowest emissions rate that can be achieved. (The actual language is "maximum degree of reductions in emissions of each air [toxic] pollutant.") Thus, for this section, while the Administrator may require any of a large number of actions, including changes in the production process, the Administrator cannot require shutdown since the rate of emission is to be minimized, not the volume of emissions.

Concerning whether all elements of the decision, including non-environmental considerations, should be treated equally, present analysis methods do not provide a demonstrable way to assure equality of treatment of these factors. Therefore, the usual requirement has been to make a specific environmental decision, "taking into account" a number of specified factors.

Questions from Senator McClure on Oxygenated Fuels

Question 1:	The Senate Environment and Public Works Committee Reported bill would require all 44 carbon monoxide nonattainment areas to implement an oxygenated fuels program containing a minimum of 3.1 percent oxygen. Since ethanol is the only fuel in widespread commerce that can meet the 3.1 percent requirement, S.1630 also has a so-called oxygen credits trading program. As I understand the effect of this provision, however, it would result in a minimum of a 45-50 percent set aside for ethanol in those 44 carbon monoxide nonattainment areas. Could you tell me what the Administration's position is on the oxygenated fuels provision in S.1630 and how the Administration's bill approaches this issue?
Answer:	The approach in the Administration's bill is to let states with nonattainment areas determine the specific oxygen content of gasoline "as is necessary, in combination with other measures to meet the carbon monoxide air quality standard". The oxygen content level for gasoline is not specified in the Administration's proposed clean air amendments. In contrast, S.1630 mandates a 3.1 percent oxygen content requirement for all gasoline sold from October 1st to March 31st for the 44 areas that are not in attainment for carbon monoxide. We estimate that approximately 4 billion gallons of blends (ethanol, ETBE, MTBE) would be needed to satisfy the 3.1 percent requirement and existing demand for blends. (This would not include any

Answer 1 Continued:

additional amounts for reformulated gasoline.) Current industry capacity in the U.S. including imports produces about 1.9 billion gallons for sale. Thus, a 100 percent increase in production and imports would have to occur to meet the requirement by October 1, 1991. This is not feasible. Therefore, the requirement cannot be met for at least 3-4 years and, if imposed, will result in sharply higher gasoline prices and widespread noncompliance.

If implemented, the increased economic cost of production is $1.6 billion annually, and the budget deficit would be increase by $1.0 billion from FY 1992 through FY 1995 because of the Federal 60 cents per gallon subsidy for ethanol. The Highway Trust Fund would lose substantial tax revenue earmarked for highway construction. The budget deficit increase occurs at a time when spending must be controlled to meet G-R-H deficit targets.

Answer 1
Continued:

Further, EPA projects that under the President's proposals, by 1995, over 30 of the 44 areas will be in attainment for carbon monoxide without mandated oxygenated fuels. By 2000, EPA projects the number of nonattainment areas drops to fewer than 10. Thus, the incremental economic and budget cost of the 3.1 percent mandate is totally unnecessary in all but a few areas.

The 3.1 percent mandate would mean that a substantial portion of the requirement would be met by ethanol because of the 60 cents per gallon Federal subsidy. There would not be significant farm program budget savings since acreage set-asides for corn would be reduced as demand for corn related to ethanol increased. In addition, soybean producers would be placed at a disadvantage as animal feed production, a byproduct of ethanol production, increases, displacing soybean market share. This could result in demands by soybean producers for Federal subsidy protection.

Answer 1
Continued:

In sum, the 3.1 percent mandate in 44 cities is not feasible, not needed, and will incur substantial economic budget costs to the nation at a time when wasteful spending must be reduced. The Administration strongly prefers its proposal providing the states and affected metropolitan areas with the flexibility to decide which measures are most effective to achieve carbon monoxide compliance and is strongly opposed to the 3.1 percent requirement for the 44 areas.

Prepared by: Margaret Singh PHONE: 586-5590 DATE: 7/23/90
DIR INIT.
LGS 7/24/90

QUESTIONS FROM SENATOR McCLURE

Costs

Question 1: Has your Department done a nationwide or a state-by-state cost analysis of each of the Titles of S. 1630 and S. 1490? If so, what are the results, title by title, and how do they compare with the Business Roundtable results released this past week? Please, also, explain if you can the reasons for any differences in the numbers.

Answer: The Department of Energy has relied primarily upon the cost analysis done by the Environmental Protection Agency (EPA) for all the titles of the Clean Air Act. The cost comparisons of the Administration's proposal, the House bill H.R. 3030, and the Senate bill S. 1630 are attached.

The Business Roundtable issued its report on cost estimates for the Clean Air Act amendments on January 18, 1990. The Business Rountable report starts with the Administration's proposal, and then builds upon the proposal as more stringent emission standards or more stringent air toxic health risk standards are imposed. The Business Rountable estimated the Administration's proposal would cost about $22 billion anually. The Administration estimates that its proposal would cost about $19 billion annually. The House bill H.R. 3030 is similar to the Business Roundtable estimate and would cost $22 billion annually. Thus, the Administration and the Business Rountable are very close in their estimates of the costs of the Administration's Clean Air Act initiative. The enormous increase in the Business Rountable's cost estimates for S. 1630 derive from the

Answer 1
(continued):

mobile source and air toxics standards in S. 1630. If the highest residual risk standard in the air toxics title was implemented, namely, a 1-in-a-million standard, the Business Roundtable estimates that this would add $55 billion annually to the cost of the Clean Air Act amendments. If all of the maximum standards of the Senate's bill were implemented, the Business Roundtable estimates that the annual cost of the Clean Air Act amendments would be $104 billion annually.

QUESTIONS FROM SENATOR WALLOP

Question 1: The Administration supports an emissions cap for SO_2 and NO_x after the year 2000. The States that have already undertaken the expense of reducing emissions would be penalized under this proposal because they would receive no credits for past effort. The dirty States would receive the credits, and could add new facilities after 2000. How do you propose to equalize the treatment of both clean States and dirty States?

Answer: The Administration's initial proposal did not intend to "penalize" clean States. The initial proposal was intended to create incentives to clean up the dirtiest units in the nation, to permit a flexible implementation strategy, and to rely upon a cost effective, market-based approach. The perceived, but unintended, consequence of the Administration's proposal is to limit the growth potential of those units that already have cleaned up below the emission levels required in Phases I and II of the President's proposal.

Several alternatives were proposed to allow clean units more opportunity to increase emissions over the 1985 baseline without having to purchase additional allowances. The Administration supports section 405 of S. 1630 which would increase the baseline by 20 percent in order to accommodate growth by the cleanest units.

QUESTIONS FROM SENATOR WALLOP

Question 2: It appears that some groups would prefer to limit the credits that the Western States could trade for new growth with the Midwest or Eastern States. Their argument appears to be that the Western States already have clean air, and allowing them to trade with Eastern regions would increase pollution in the East. What is the Department's position on limiting the value of Western credits?

Answer: In the Department's opinion, there should be no disparity in the treatment of allowances within the allowance trading system. S. 1490 and S. 1630 would create two allowance trading regions that are indentical in both Phase I and Phase II. Presumably, but not necessarily, these regions will be divided between 17 western states and 31 eastern states. The idea behind the creation of these two regions was to maintain the relative cleanliness of the western ambient air while creating incentives for the eastern region to clean up existing plants. New units, however, will be able to obtain allowances from anywhere in the country. Thus, new units needed to accommodate growth in the West may purchase allowances from the East, the same as could a new unit to be located in the East. The value of allowances should be about the same in either region because if the value of the western allowances were lower than the value of the eastern allowances new units would bid up the price of the western allowances until all allowances reached an equilibrium value.

QUESTIONS FROM SENATOR MURKOWSKI

Question 1:	To what extent does the acid rain reduction program promote and facilitate the use of low sulfur coal?
Answer:	The requirements of both Phase I and Phase II of Title IV of S. 1630 will lead to greater use of low sulfur coal. Low sulfur coal is not "promoted" through any explicit incentive, but rather by the market response to the stated emission reduction provisions. In general, low sulfur coal is a more cost-effective method to reduce moderate amounts of SO2 than high removal technologies, like scrubbing. As a result, coal switching tends to be the compliance alternative of choice, until its potential is exhausted, after which scrubbers and advanced technologies become attractive. S. 1630 requires more SO2 reduction than can be economically provided by coal switching alone. As a result, there is a mixture of coal switching and technological systems of emission reduction in the results of all analyses of S. 1630. The analysis of S. 1630 by ICF Resources, Inc., for the Environmental Protection Agency indicated that about 110-120 million tons of high sulfur coal production from Northern Appalachia and the Midwest would be displaced by lower sulfur coal from other regions. The results did not indicate how much intra-regional coal switching would take place. Hence, there is no good estimate for the

total amount of low sulfur coal use expected as a result of the legislation.

QUESTIONS FROM SENATOR MURKOWSKI

Question 2: I have seen in the committee report that Alaska is exempted from Phase II of the acid rain program. Is it your understanding that Phase II only applies to the 48 contiguous states?

Answer: Both the President's proposal and the Senate bill state in the purposes section of the bill (section 501(b) of S. 1490 and section 401(b) of S. 1630) that the SO_2 and NO_x reductions will apply to the 48 contiguous states and the District of Columbia. In both bills, the term state (section 502(11) of S. 1490 and section 402(m) of S. 1630) is defined as one of the 48 contiguous states and the District of Columbia. It is clear from both bills that Phase II will apply only to the 48 contiguous states and the District of Columbia.

QUESTIONS FROM SENATOR MURKOWSKI

Question 3:	**The senate bill specifically lists clean coal technologies that will qualify a utility for an extension of their emission reduction obligation. Why is that? What about Clean Coal Technologies that have qualified for Department of Energy grants but are not on this list?**
Answer:	The Department supports compliance date extensions only for those Clean Coal Technologies that are projected to be commercially available beyond the compliance date target of December 31, 2000, and that offer increased efficiency without generating toxic wastes.

Those Clean Coal Technologies that have qualified for Department of Energy support but are not repowering technologies on the list for extension are projected to be commercially available by the compliance target date of December 31, 2000.

A technology has reached commercial availability when it is ready for widespread deployment. To reach this point, a technology would have to undergo an initial demonstration to prove technical readiness followed by a few replications of the technology in different operating environments. The latter is required to provide assurances of reliability, operability, cost and performance required by electric utilities to commercially deploy any advanced technology.

QUESTION FOR THE RECORD

Question 1: WEPCo Decision. Please describe what has been called the WEPCo decision and its effect on DOE's Clean Coal Technology program.

- Please explain the effect the WEPCo decision might have on potential conversion of coal or oil units to natural gas?
- On September 29 and December 13, 1989, DOE asked EPA to clarify its position on WEPCo, through a policy statement. Has EPA responded and has their response been satisfactory?

Answer: WEPCo is a buzzword for an adjudicative determination made by EPA Administrator Lee Thomas in an October 14, 1988, letter to the Vice President of Wisconsin Electric Power Company (WEPCo). WEPCo had asked EPA if certain maintenance and repair activities at its Port Washington power plant would be defined by EPA to be "modifications", a term which means that the existing unit would become subject to more stringent air pollution provisions usually applied only to new plants. The EPA determination was affirmative, and the term "WEPCo" has since been used to describe the set of regulations and policies which result in new source regulations being applied to existing sources undergoing certain types of changes.

The relationship between this case and the Clean Coal Technology demonstration program is that, under the existing policy, installation of pollution control equipment at an existing unit, including Clean Coal Technology, is considered a "non-routine change" which can trigger new source review requirements. (In some cases, sources can agree to install even additional control equipment, or agree to restrict their operation, and avoid new source review. However, most utilities would prefer not to agree to such measures.) Because utilities have difficulty justifying a demonstration project which exposes the utility to greater environmental control costs, the WEPCo policy serves as a disincentive to utility participation in the CCT demonstration program.

The WEPCo decision can deter conversions of coal and oil units to natural gas. A "modification" is predicated on two factors: 1) A "non-routine" physical change or change in the method of operation of a unit; and, 2) an emission increase, based on actual emissions before the change and potential emissions after the change (considering pollution controls and stipulations to limit hours of operation). Clearly, conversion of a unit designed to burn only coal or oil to burn an additional fuel is "non-routine". Because of the basis for comparison (actual to potential), even substitution of a relatively clean fuel for a relatively dirty fuel (e.g., gas for coal), could still result in a calculated emission increase, as long as there was still a substantial amount of coal burned at the unit. In the case of oil-to-gas conversions, operation with gas would indicate lower SO2 and particulate matter emissions, but, with the comparison noted above, NOx emissions could be calculated to increase.

With respect to DOE's letters to EPA regarding WEPCo, the two agencies both contributed to the Administration's position on WEPCo, which was outlined by Dr. Richard Schmalensee, Member, Council of Economic Advisors, in his May 8, 1990, testimony before the Senate Subcommittee on Energy Research and Development. Both agencies also participated in preparing the Administration's legislative language to address the WEPCo problem, which was conveyed to Senator Ford in a May 23, 1990, letter from Dr. Schmalensee.

QUESTIONS FOR THE RECORD

Question 2: What is the effect of the legislation, including the Lieberman amendment on the DOE uranium enrichment program? How much additional cost per SWU will this add to the SWU price that is already 30-40% over the market price? How will this affect the competitiveness of the uranium enrichment program?

Answer: The impact of the acid rain legislation upon the uranium enrichment program is substantial. The Department has estimated the impact of the President's proposals on the three coal-fired units that supply the uranium enrichment facilities. In order to meet the Phase I and II SO_2 reductions and the Phase II NO_x requirements, scrubbers and selective noncatalytic reduction (SNR) would have to be used on two of the units costing $558 million and increasing operating costs by $117 million per year. The reason for using SNR for NO_x reduction is that the units are wet bottom boilers and are not amenable to low NO_x burners, the technology called for in the Administration's proposel. The third unit likely would use low sulfur coal to meet the reductions. The capital costs involved with this unit will be $247 million, with DOE's share at $148 million. Annual operating costs would increase by $24 million, with DOE's share at $14 million. The capital costs for this unit are due to the need to increase the coal handling capability of this plant. Low sulfur coal has a lower heat content than the coal presently used. Therefore, more coal will have to be processed, increasing the costs for handling,

Answer 2
(continued):

preparation, and waste disposal. The per SWU increase from these capital and operating cost increases is estimated to be about $20 per SWU.

The Lieberman amendment imposes additional costs upon the uranium enrichment facilities. If the uranium enrichment facilities could use nuclear power to satisfy the 10-percent requirment in the Lieberman amendment, this would entail the purchase of about 500 MW of electricity with an annual cost of between $100 million and $200 million. The per SWU cost increase would be about $10, over and above the $20 per SWU cost of the President's proposal.

QUESTIONS FOR THE RECORD

Question 3: What about the effect of the legislation on other Federal facilities?

Answer: The effect of the legislation upon other federal facilities is substantial. Nationwide, the EPA estimates that electricity rates could increase up to 2 percent. With a federal electricity bill at about $2.5 billion in the last fiscal year, the increase in electricity costs would be about $50 million. The requirement to fulfill 10 percent of each federal facility's electricity requirements from renewables and other clean alternative technologies will increase the cost of electricity well above the $50 million figure. All of these are estimates since the Department has not undertaken a more comprehensive analysis of the Clean Air Act proposals on federal facilities.

QUESTIONS FOR THE RECORD

Question 4: Clean Coal Technology. Why is the extension for clean coal technologies in S. 1630 limited to repowering technologies?

- Would there be a benefit to expanding the provisions to include a time extension in Phase II for retrofit control technologies, such as natural gas co-firing technologies?
- Information available indicates that many of the clean coal repowering technologies that are listed in proposed legislation will not be available for commercial use until 2003, at the earliest. Do you believe that there may be additional cost-effective benefits to be gained from extending the Phase II deadline by a few years to encourage the use of these clean coal technologies?

Answer: The extension is limited to repowering technologies because: (1) they are the only technologies currently projected to not be commercially available before December 31, 2003 and (2) their potential advantages in terms of low emissions, high efficiency, low no waste and their ability to meet future energy needs warrants this regulated flexibility.

Other Clean Coal Technologies, including natural gas co-firing technologies, should be commercially available by the compliance target date of December 31, 2000.

However, predicting when new technologies will be available for commercial use is judgemental and subject to a number of factors (both technology and

Answer 4: (Continued)

institutionally oriented). The 2003 extension date set forth in the Administration's proposed Clean Air Act legislation reflects a balance between the urgency to reduce emissions and the projected availability of the listed technologies.

We admit the timelines are tight, and as a result, some technologies offering cost-effective approaches to meeting emission reduction targets may not be available as options given the 2003 extension date. However, the need to reduce emissions quickly must be weighed against the advantages of this further delay.

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

722 JACKSON PLACE, N.W.
WASHINGTON, D.C. 20503
202/395-5771

March 30, 1990

Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

I am enclosing responses to questions raised by the Committee on Energy and Natural Resources following its January 24 and 25, 1990 hearing on Energy Policy Implications of S. 1630.

These responses have been reviewed and approved by NAPAP's principal participating agencies, including EPA, the Department of Energy, the Department of Commerce - NOAA, the Department of the Interior, and the Department of Agriculture.

Sincerely,

James R. Mahoney

James R. Mahoney
Director

Enclosure

cc: Senator James A. McClure, Ranking Minority Member
Members of the Committee

Answers to Supplemental Questions
Following the Hearing of
The Senate Committee on Energy and Natural Resources
Held on January 24, 1990

Prepared by
James R. Mahoney
Director
National Acid Precipitation Assessment Program

March 30, 1990

Supplemental Questions

Senate Hearing of January 24, 1990

1. *Scientifically, how important are the Phase I and Phase II dates in S. 1630; what would a shift of a few years in these dates mean scientifically?*

Acid rain has damaged certain lakes and streams in the eastern United States and Canada; it contributes to visibility impairment and materials degradation; it may be a factor in the decline of red spruce at high elevations in some Appalachian Mountain locations; it may contribute to long-term (decades) changes in sensitive soils; and the question of increased human health risk associated with current levels of acidic aerosols in the atmosphere is under active investigation. A shift of a few years in the final dates for implementing acidic deposition controls would result in a similar shift in the initiation of the benefits (i.e., reduction of effects) expected from controls. For different categories of effects, the nature of the response will be different. In the categories of visibility improvement, reduction of impacts on materials, and reduced risk of health effects related to acidic aerosols, the benefits expected to result from emission reductions would occur immediately following such reductions. For the categories of impacts on sensitive surface waters and possible impacts on sensitive soils, changes in chemical status will begin when emissions are reduced, but the time periods required to realize a majority of the ultimate benefits will typically be decades. For example, for lakes and streams in the Northeast, improvements would begin shortly after emissions are reduced; recovery of approximately one half of the estimated 162[*] currently acidic lakes has been projected to occur in 50 years for SO_2 emission reductions similar to those specified in S. 1630. A shift of a few years would similarly shift the initiation of these changes in surface water chemistry. Improvements in the biological status of these waters would be expected to follow after chemical changes. For lakes and streams in the mid-Atlantic and Southern Blue Ridge regions, the response time is projected to be longer than in the Northeast. Reduced SO_2 emissions may also reduce the impact of episodic events that can result in rapid declines in lake pH levels and possible biological impacts.

Clean coal technologies are expected to become commercially available at approximately the time the proposed Phase II becomes effective. These technologies have a number of environmental, energy efficiency and economic advantages when compared to currently available scrubber technology (e.g. more manageable waste-products, reduced emissions of greenhouse gases, increased removal of nitrogen oxides). Therefore a Phase II schedule that allows commercial application of Clean Coal Technologies has advantages worthy of consideration, in balance with the factors favoring early emission reductions.

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[*] Based on the National Surface Water Survey of lakes larger than 4 hectares (approximately 10 acres). A larger number of small lakes (i.e., less than 4 hectares) in the Northeast are also acidic, from all causes.

2. *The legislation before us makes certain assumptions regarding current trends in emissions. From the standpoint of the credibility of the methodology and the data sources used, would you characterize the differences between the EPA National Trends estimates and the NAPAP/ANL Current Emission Trends estimates?*

   a) *What sources of information were used?*
   b) *At what level of detail were the estimates made?*
   c) *How well is the methodology defined?*
   d) *What can be said about the relative accuracy of the annual estimates?*

The information necessary to answer this question has previously been developed in response to an inquiry from Chairman Dingell of the House Committee on Energy and Commerce. A similar response has also been prepared in response to an inquiry by Representative Howard Nielson. A copy of the analysis for Chairman Dingell is attached. We believe this will fully respond to your question. We would be pleased to provide any further information you may request.

3. *From the point of view of the extensiveness and objectivity of the review, how do the EPA National Trends and the NAPAP/ANL Current Emission Trends compare?*

   a) *How well are the processes defined?*
   b) *How much interagency and NAPAP Peer Review has been accomplished for each model?*
   c) *How much private sector review has been published on each?*
   d) *What documentation substantiates the reviews?*

Similar to Question 2, the information necessary to answer this question is contained in the analyses performed for Representative Dingell (attached). In particular, please see the response on pages 7 (bottom half) and 9 of the letter. We would be pleased to provide any further information you may request.

4. *Have scientific views on acid rain changed in the 1980s and how?*

When NAPAP initiated its research activities in 1981, the range of scientific opinion on the effects of acid rain was very wide. Some viewed acid rain as a rapidly intensifying ecological catastrophe, while others viewed the allegations of damage as speculative hypotheses without sufficient substantiation. After nearly a decade of research both of these positions can now be rejected. As measurement data and modeling methods have developed in recent years, most scientists would agree that the effects of acid rain are neither unsubstantiated conjecture nor an acute ecological crisis. This evolution of scientific views is illustrated in Figure 1. We know that acid rain has damaged certain lakes and streams in the eastern United States and Canada, that it contributes to materials degradation and visibility impairment, that it may be a factor in the decline of red spruce at high elevations in some Appalachian Mountain locations, that it may contribute to long-term changes in sensitive soils, and that the question of increased human health risk associated with current levels of acidic aerosols in the atmosphere is under active investigation. On the other hand, we know that the time required for significant change in the regional patterns of acidity in lakes and streams is long (decades), that the majority of forests in North America are healthy, that no regional patterns of crop damage attributable to acid rain have been detected in North America, and that current levels of ozone create significantly greater risk to human health and potential for damage to forests and crops, compared to acid rain.

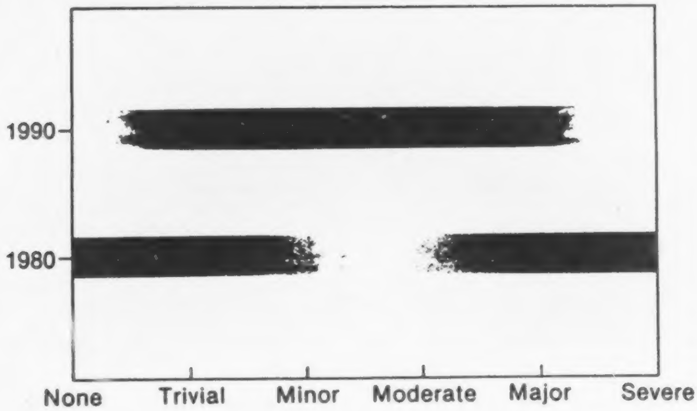

Figure 1. The Changing Distribution of Scientific Views Concerning the Evidence of Acid Rain Effects.

5. *What is the best estimate of emission reductions that would be obtained from S. 1630 or S. 1490?*

The only thorough analysis NAPAP has conducted on proposed emissions reductions is for H.R. 3030 and is described in detail in the enclosed response to Chairman Dingell of the House Committee on Energy and Commerce. Although there are differences among S. 1630, S. 1490 and H.R. 3030, our best estimates of anticipated reductions for S. 1630 and S. 1490 is approximately the same as our estimate for H.R. 3030.

6. *The cost of implementing this proposed acid rain control measure has been estimated to be as much as $5 billion annually, yet this expenditure will only accelerate today's on-going SO_2 decreases already mandated by the existing Clean Air Act. In light of NAPAP's pronouncement that there is no impending acid rain crisis, how can we justify such a high cost for merely accelerating the progress we are and will make in lowering total emissions of SO_2?*

The role of NAPAP is technical fact finding; NAPAP does not make public value judgments such as whether the benefits of acid rain controls outweigh the costs. Therefore it is not appropriate for NAPAP to comment on how to justify "...such a high cost for merely accelerating the progress we are and will make in lowering total emissions of SO_2."

NAPAP's Integrated Assessment, to be completed by September 1990, will report comparative evaluations of the costs and benefits associated with a range of acid rain control strategies. Because of the time required for peer review of the underlying scientific evaluations and projection model methodologies, and for preparation and review of the projection estimates this schedule cannot be shortened. Whereever possible, NAPAP will provide update information as soon as it is available between now and September.

7. *What are the effects, if any, of acid rain on Western states?*

There are virtually no acidic lakes in the West. While many western surface waters are sensitive to acidification (i.e., they have low acid neutralizing capacity), the levels of acidic deposition in the West are substantially lower than those in the East. The only acidic lake (ANC < 0 ueq/L) sampled in the Western Lake Survey was associated with a thermal spring that has high natural quantities of sulfur, an acidic anion. There was no regional evidence of chronic (i.e., long-term) acidification, and the conclusion of the Western Lake Survey was that chronic regional acidification is not now a problem in the West.

It is important to realize that the design of the Western Lake Survey was to determine chronically acidic lakes and as such called for a single sample to be taken in the fall. Therefore, nothing can be said from these data about the possibility of the effects from episodic (i.e., short term) acidic pulses associated with snowmelt episodes or rainstorms on lakes or streams in the West that may be associated with acidic deposition.

There is evidence that trees and forests in southern California and along the western Sierra Nevada in central California are adversely effected by current levels of ozone and other oxidants. No benefits (improvements) in these forest effects would be expected from SO_2 emission controls, because ozone levels are not influenced by SO_2 emissions. We are not aware of other regional patterns of forest damage in the West resulting from current levels of air pollutants. However, we are aware that some western forests and high-elevation ecosystems might be sensitive to acidic deposition. Two of the NAPAP member agencies are conducting studies in the Rocky Mountains, the Northwest, and in southern California to (1) assess the sensitivity of tree species to acid deposition and other pollutants, and (2) determine whether there are previously undetected cases of forest damage that might be associated with air pollutants.

Visibility monitoring by the National Park Service (NPS) has indicated that scenic vistas are affected by air pollution at all 35 NPS monitoring locations within the contiguous 48 states. Degradations in western visibility have not been as severe as in the East. Summer visual range is generally lower than winter, and there is a wide range in visibility from park to park and even within a park.

There is concern that air pollutants, including acidic deposition, contribute to materials degradation in the Los Angeles air basin. The California Air Resources Board is currently preparing an assessment of acid deposition damage to sensitive materials resources.

8. *Scientifically, how important is a ten million ton reduction; what would be the difference resulting from a eight million or 12 million ton reduction?*

In commenting on this question, we note the following comparisons:

- **maximum national SO_2 emissions (1973) – 31 million tons**
- **1985 emissions (NAPAP inventory) – 23 million tons**
- **post 2000 projection under S. 1630 – 15 million tons**

An eight million ton reduction[*] would result in a post-2000 projection of 17 million tons, and a twelve million ton reduction would result in a post-2000 projection of 13 million tons.

As described in the NAPAP Assessment Plan Update (August 1989), we are analyzing the projected environmental outcomes for "sensitivity cases" of emission reductions both greater and less than 10 million tons. Because of the time needed to prepare, conduct, review, and analyze the calculations, these results will not be available until June 1990 at the earliest. The following qualitative comments are based on NAPAP's consideration of the available measurement data and of the theoretical modeling approaches:

- **As far as environmental benefits alone are concerned, greater emission reductions would always be preferred, compared to lesser reductions.**

- **We know that the relationship between emissions changes and effects is not always proportional. However, as a workable first estimate, the regional patterns of benefits associated with an 8-million ton SO_2 emission reduction might be viewed as approximately 80% of the benefits that are projected to result from a 10-million ton emissions reduction. In other words, we do not expect a strong non-linear change in the regional patterns of effects to result from a small percentage change in emissions.**

- **If post-2000 emissions levels were to change by 13% (i.e., from a 15 million ton permanent level to 17 or 13 million tons), the regional patterns of the effects of concern (e.g. aquatic systems, high elevation red spruce, materials degradation) would likely change by small amounts, but such changes would likely not be measurable over a period of many years. It is unlikely that differential environmental effects over large regions could be measured between cases where the national emission levels would differ by two million tons. However, if such differences in emission levels were concentrated within a small region, then distinctive differences in environmental effects within the region might be observed.**

- **Even when regional differences in effects (related to small differences in emission levels) are difficult to measure over periods of several years, such differences may occur, and may be observed over longer periods such as decades.**

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[*] The various reduction levels (eight, ten and twelve) are referred to 1980 SO_2 emission levels in the bill. The estimated 1980 level is the subject of questions 2 and 3 in this document.

ATTACHMENT

NAPAP Correspondence With
Representative John D. Dingell
(Reference to questions 2, 3 and 5)

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM
722 JACKSON PLACE, N.W.
WASHINGTON, D.C. [illegible]
[illegible]

February 5, 1990

Honorable John D. Dingell
Chairman, Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Dingell:

I am writing in response to your letter of November 7, 1989, in which you requested NAPAP's evaluation of the SO_2 emission baseline from which a ten million ton emission reduction is calculated for use in Title V of H.R. 3030, the President's comprehensive Clean Air Act bill. Since receipt of your letter on November 24, NAPAP has conducted extensive analyses of this issue, based on information provided by the Environmental Protection Agency (EPA), the Department of Energy (DOE) and the technical consultants retained by the Edison Electric Institute (EEI). This letter and its enclosures describe the NAPAP analyses, present our findings, and respond to other specific questions you have raised.

The letter presents the best judgment of the NAPAP Office of the Director (OD) on the technical issues, based on our review of all relevant information currently available. While our response has been reviewed by the NAPAP participating agencies, it does not represent an adopted position of those agencies. NAPAP has reviewed the emissions information developed by two of its participating agencies, EPA and DOE, as well as the information available from other government and nongovernment sources. This letter presents the NAPAP OD's best technical judgments in response to your request, and does not constitute the position of either EPA or DOE.

NAPAP has received a similar request for review of emission reduction estimates from Representative Howard Nielson, in a letter dated November 20, 1989. For reference, copies of your letter and that of Representative Nielson are in Enclosure 1. In view of the similarity of the two requests, Part A of this letter contains the same information as in our response to Representative Nielson. Parts B and C of this letter respond to other specific questions you have asked.

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[f] The column shows NAPAP OD's estimate of the plausible range for each category, as defined in the text of this letter. The reasons for choosing the range adopted for each category are explained in individual footnotes below. Ranges for subtotals generally do not equal the sum of the maximum and minimum values of the component ranges; the sums have been reduced on the assumption that the extreme values in the ranges for all components would not occur simultaneously in one direction.

[g] The column shows NAPAP OD's best judgment for each category, as defined in the text of this letter. This is represented by either a single value or the smallest range NAPAP OD judges to be appropriate. Within the best judgment range, NAPAP OD has no basis to prefer any one value. The reasons for choosing the best judgment estimate in each category are explained in individual footnotes below.

[h] Values for 1980 and 1985 were estimated by ICF. **Comments:** (1) Different emission factors, which represent the conversion of sulfur in fuel to SO_2 in the combustion products, were used by ICF for 1980 and 1985. This creates a bias in the estimated trend. Correction of this bias would add approximately 0.4 million tons to the 1.1 million ton decrease (i.e., a corrected decrease of 1.5 million tons). (2) The 1980 value from ICF was based primarily on data from FPC Form 67, which may not be the most accurate source of data for that year. (3) The 1985 value was developed using information on flue-gas desulfurization units in place, based on the 1984 EIA Form 767. The 1984 Form 767 was the latest available at the time the estimate was made, but does not accurately reflect 1985 removal rates and is not as accurate as the 1985 Form 767 or the NAPAP emissions inventory data for FGD units in 1985.

[i] The 1980-1985 difference was calculated by TBS from the value of 17.48 million tons for 1980 (based on the 1980 NAPAP Inventory) and a value of 16.14 million tons for 1985 (which was estimated by TBS using data primarily from the 1985 Form 767, supplied to TBS by the Utility Data Institute). **Comments:** (1) The 1985 emission estimate for small (nonaffected) units with high emission rates is higher, and the estimate for large (affected) units with high emission rates is lower, than estimates from other sources, including the 1985 NAPAP inventory. These possible inaccuracies in the TBS 1985 emission values affect both the historical trend estimates and the future projections made by TBS. (2) Differences in data and methodologies between the 1980 NAPAP and 1985 TBS estimates result in inconsistencies. To avoid bias, it is best to use a consistent method from year to year when estimating trends. (3) The TBS 1980-1985 trend value is judged plausible, but is not in the best judgment range.

[j] For 1985, the value was calculated by ANL based on boiler-level data from the 1985 EIA Form 767. For 1980, it was based on estimated boiler-level data (using plant-level data from EIA Form 759 and FERC Form 423 and boiler-to-plant relationships from 1985-87 Forms 767). FGDs are assumed to operate only enough to meet emission standards. **Comments:** (1) In general, use of boiler-level data in this method enhances the quality of emission estimates. It also projects higher estimates of utility emission reductions between 1980 and 1985, since the boiler level data in Form 767 indicate that units with FGD are operated at higher capacity factors than units without FGD. Values are viewed as preliminary until a full review of the methodology and resulting values has been conducted.

PART A - NAPAP OD'S ESTIMATES OF POST-1980 SO_2 EMISSION REDUCTIONS EXPECTED UNDER H.R. 3030.

Analysis Approach

Subsequent to receiving the letters from Representatives Dingell and Nielson, information copies were immediately sent to all NAPAP participating agency representatives (letters and memoranda of November 24, 27 and 29; Enclosure 1). On December 11 we asked EPA, DOE, the Office of Technology Assessment (OTA), and EEI to provide us with information about any relevant analyses they had conducted (letters in Enclosure 1). No relevant analyses had been conducted by OTA. On December 20 DOE responded with a summary of its "non-NAPAP" analyses relevant to these questions (Enclosure 1). The majority of DOE's analyses on these questions have been developed as part of the NAPAP program, and are discussed below. The responses of EPA and EEI are also discussed below.

Representatives of EPA, DOE, and Argonne National Laboratory (ANL - who produce emission trends information for NAPAP), met on four occasions between December 15, 1989 and January 9, 1990. Other EPA representatives from the Office of Research and Development and the Office of Air Quality Programs and Standards (OAQPS) in Research Triangle Park, North Carolina participated by teleconference link. Representatives of ICF Resources, Inc. (EPA technical contractor) and Temple, Barker and Sloane, Inc. (TBS, EEI technical contractor) participated in some of these meetings.

NAPAP OD developed a set of questions aimed at determining the reliability of the various SO_2 emissions trends estimates (Enclosure 1). Responses from TBS, DOE and EPA were received and analyzed by NAPAP OD, and reviewed by the technical representatives of each responding organization. EPA provided information about three different analyses -- (1) the historical estimates and future projections carried out by ICF, (2) the NAPAP 1980 and 1985 emissions inventories developed by EPA for NAPAP, and (3) historical emission trends estimated by EPA/OAQPS. In some cases, additional information was requested by NAPAP. The summaries of methodologies and supporting information are documented in Enclosures 2 through 6 as follows:

Enclosure 2 - EEI (TBS)

Enclosure 3 - EPA (ICF)

Enclosure 4 - EPA -- NAPAP Inventories (1980 and 1985)

Enclosure 5 - EPA Trend Analyses

Enclosure 6 - ANL/DOE Analyses prepared for NAPAP

NAPAP OD analyzed and cross-checked the various data sets and queried representatives of each of the organizations involved in the analysis.

In order to present its findings in a format consistent with the analyses reported by EPA and EEI, NAPAP OD adopted the following nine categories for aggregating the 1980 to 2000 national SO_2 emission change estimates:

A. Electric Utility Emissions

   1. Total estimated change: 1980 to 1985

   2. Reductions expected between 1985 and 2000 at affected units as defined in H.R. 3030

   3. Changes expected between 1985 and 2000 at electric utility facilities not affected by the control requirements of H.R. 3030 (facilities under 75 MW capacity and/or under a 1.2 lbs/MMBtu emission rate in 1985).

   4. Emissions from new (post-1985) facilities, after subtracting the offsets required for units that come on line after the bill is enacted (assumed to be in 1990).

   5. Adjustment for additional emissions allowed for sources repowering with technologies specified in H.R. 3030.

   6. Adjustment for operating margins (i.e., additional emission controls beyond those required under the allowance system) to assure regulatory compliance.

B. Nonutility Emissions

   7. Total estimated change: 1980 to 1985

   8. Transportation sector SO_2 emission reductions expected between 1985 and 2000, resulting from the reduction in sulfur content of diesel fuel required under Title II of H.R. 3030.

   9. Post-1985 changes in emissions from nonutility stationary sources (industrial, commercial and residential).

NAPAP OD evaluated the EPA and EEI estimates in each of these nine categories and, where available, also evaluated analogous information available from three other sources: (1) ANL/DOE analyses prepared for Task Group I (Emissions and Controls) of NAPAP, (2) EPA emission trend analyses, and (3) comparison of the NAPAP 1980 and 1985 emission inventories.

Recognizing that no estimate is entirely free of error, NAPAP OD evaluated the available estimates in each of the nine categories. NAPAP OD applied the following criteria in developing its evaluations:

1. Appropriateness of the methodology employed to develop the estimate

2. Adequacy and representativeness of the input data used

3. Degree of peer review achieved for the methodology and data used

4. Estimated effects of systematic biases (where identified) in the methodology and data employed

5. Comparability of the 1985 emission estimate produced by the methodology to the corresponding value from the 1985 NAPAP inventory, which is judged to be the best source of emissions data for that year.

The NAPAP Office of Director has adopted two definitions to express its evaluations of the various emission change estimates:

> Best Judgment -- This represents the value or range which, considering all currently available evidence, the NAPAP OD judges to be the most likely estimate for the subject emission change. When a range (rather than an individual value) is expressed, NAPAP OD judges that any number within the range is equally probable; no more specific estimate of the best estimate is supportable.
>
> The NAPAP OD has developed a best judgment for each of the nine categories noted above, as well as for the subtotals for utility and nonutility emissions, and finally for the grand total of all emission changes. In developing the subtotal ranges, NAPAP OD narrowed the extreme limits, because the most likely range for summed estimates will generally be smaller than the sums of the ranges for the individual estimates.
>
> Plausible Range -- This represents the range of values which, considering the uncertainties in the available methodologies and data, NAPAP OD judges could be estimated with the use of reasonably defensible methodologies and data. Plausible range values outside of the best judgment range are considered to be less probable than values within the best judgment range.

The NAPAP OD's summary and evaluation of the available emission change estimates is presented in Table 1 and its footnotes, which immediately follow the signature page this letter.

Findings

The following statements summarize the NAPAP OD findings. All of the statements should be reviewed as a group. Taken together, they define the uncertainties and confidence limits that should be associated with the findings.

1. Compared to other nations, the United States most likely has the best SO_2 emissions information, the most advanced system of emissions reporting, and the best developed system of projecting future emission levels.

2. Despite the sophistication of the U.S. emission information, it is not possible to reduce the uncertainty of the total national estimate of post-1980 emission changes projected to result from implementation of H.R. 3030 to less than approximately one half million tons of SO_2.

3. EPA used the best information then available during the period from March to June 1989 when it developed its estimates of the emission allowance limitations that would be needed to attain the President's goal of 10 million tons of SO_2 reduction compared to 1980 levels. Specifically, EPA rejected the use of a subtraction of the NAPAP 1980 and 1985 inventories as a means of estimating the 1980 and 1985 national emission changes. Because of some errors in the data in the 1980 NAPAP inventory (which was the first national inventory prepared by EPA for NAPAP) and inconsistencies between the methods used and quality control applied in the 1980 and 1985 NAPAP inventories, NAPAP agrees that subtracting the emissions estimated from the two inventories is less reliable than other available methods for estimating 1980 to 1985 changes. NAPAP judges that the 1980 NAPAP inventory has usefulness for evaluating and cross-checking emission changes in specific categories, but should not be used as the best estimate of the overall 1980 to 1985 national emission trend.

4. The 1985 NAPAP Emission Inventory, Version 2 (also prepared by EPA for NAPAP) is widely acknowledged to be the best available reference for U.S. emission levels. Unless subsequently modified to reflect any improvements resulting from continuing analysis, the NAPAP 1985 Inventory should be used as the reference base for emission change analyses whenever possible.

Findings 5 through 8 are based on the analyses summarized in Table 1 and its associated footnotes. The footnotes explain the basis and limitations of NAPAP OD's judgments in the case of each number reported. The footnotes should be considered together with the Table.

5. For total emissions, the 1980-2000 decrease resulting from H.R. 3030 is estimated as follows:

   EPA Estimate - 9.8 to 10.3 million tons

   EEI Estimate - 12.7 to 13.0 million tons

   NAPAP OD Best Judgment - 10.6 to 11.3 million tons

   The plausible range is estimated to be 9.8 to 12.3 million tons. Values at extreme ends of the plausible range are considered to be significantly less likely than values in the best judgment range.

6. EPA's original (1989) analysis of the electric utility emissions decrease contained an inadvertent error as a result of an inconsistency in the emission factors applied for 1980 and 1985.

This error was discovered as part of our review. Adjustment of the value to account for the error increased EPA's estimated 1980-1985 emission decline by 0.4 million tons, which accounts for approximately half of the difference between NAPAP OD's current best judgment of the expected 1980-2000 decrease and the value from EPA's 1989 analysis.

7. For the electric utility subcategory, the emission reductions estimated by EPA, EEI and this analysis are remarkably similar, if two adjustments are adopted: (1) the EPA estimate of 1.1 million tons for the 1980 to 1985 reduction is increased to 1.5 million tons to correct for the error in the application of emission factors (see Finding 6), and (2) the EEI claim of credit for operating margins is disallowed, except for a very small annualized range of 0.0 to 0.1 million tons. (See footnote ** to Table 1.) Given those two adjustments, the decreases projected for the 1980 to 2000 period are:

Adjusted EPA Estimate - 8.7 to 9.2 million tons

Adjusted EEI Estimate - 8.7 to 9.1 million tons

NAPAP OD Best Judgment - 8.8 to 9.3 million tons

The best judgment range is slightly higher than either of the other estimates, for the reasons discussed in the footnotes to Table 1.

8. For non-utility emissions, the projections of the 1980-2000 change under H.R. 3030 are markedly different in the EPA and EEI analysis:

EPA Estimate - 1.5 million tons

EEI Estimate - 3.5 million tons

NAPAP OD Best Judgment - 1.8 to 2.0 million tons

The best judgment range is, at its midpoint, 0.4 million tons above the EPA estimate and 1.6 million tons below the EEI estimate, for the reasons discussed in the footnotes to Table 1.

PART B - ANSWERS TO SPECIFIC QUESTIONS ASKED IN THE LETTER OF NOVEMBER 7

Answers to the questions asked in your letter of November 7, 1989 are provided below. References are made to appropriate notes to Table 1, and to material in the enclosures that expand further on NAPAP OD's answers.

Question: I understand that there are at least two emissions inventories, one for 1980 and one for 1985. I would like a comparison of both. What methodologies were used?

Answer: Two comprehensive inventories -- for 1980 and 1985 -- have been developed by NAPAP. These are described in Enclosure 4. These inventories were developed primarily using information supplied by state air pollution control agencies to the U.S. EPA. For the 1985 inventory, state-supplied data were thoroughly checked and subjected to an intensive quality assurance and control procedure. This intensive checking did not take place for the 1980 inventory, which was the first NAPAP inventory. In addition, for the 1980 inventory, some of the state-supplied data (for utilities and smelters) were replaced with calculated emission estimates. (See note " and " to Table 1, and Enclosure 4.)

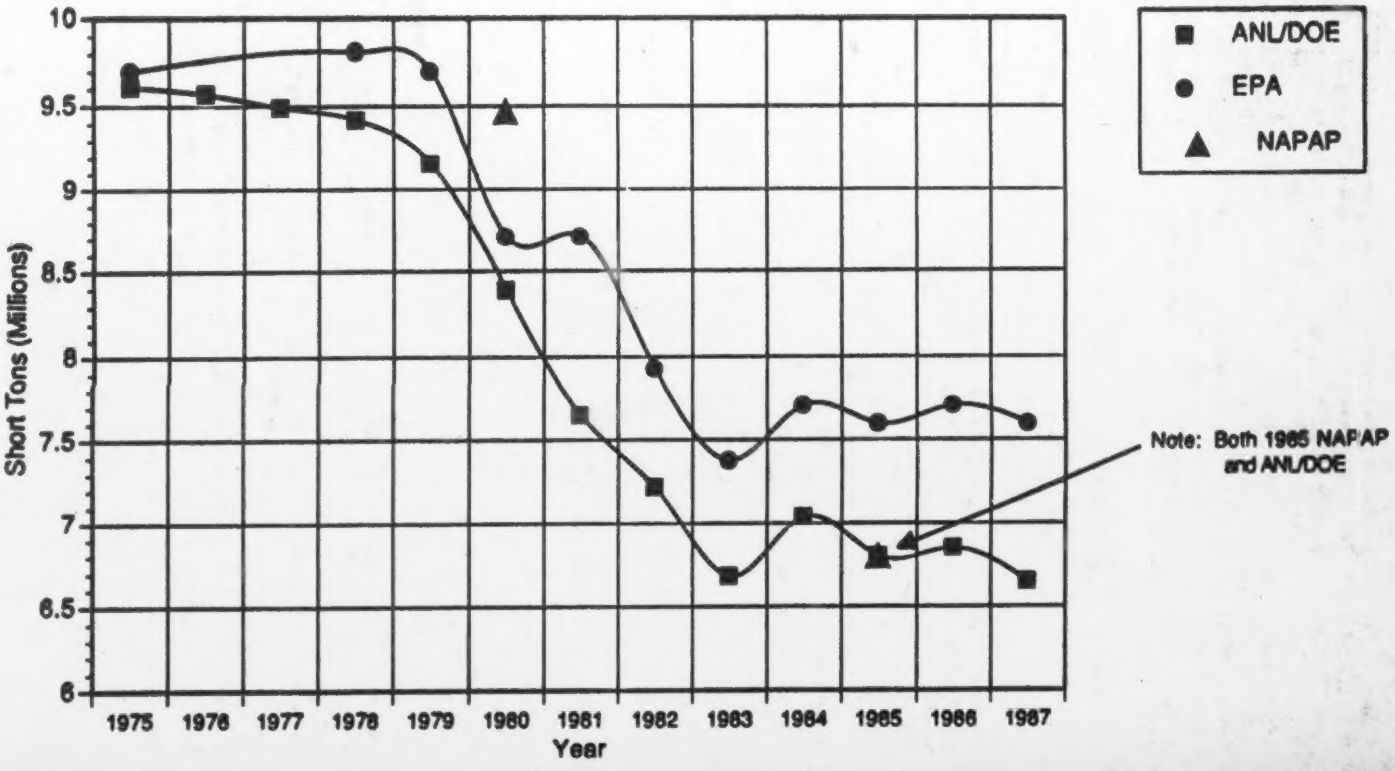
Question: What were the actual emissions for both the electric utility sector and the non-utility sector? What credits in emissions reductions should be granted to each sector? How are those credits calculated?

Answer: Various estimates of the emissions in 1980 and 1985 are available in the first pages of Enclosures 2 through 6. NAPAP OD has reviewed and critiqued these estimates. The best currently available estimate of SO_2 emissions in 1985 for utilities is 16 million tons and for nonutility sources is 7 million tons (both estimates are from the 1985 NAPAP Emissions Inventory). The best judgment of the 1980-1985 decrease in SO_2 emissions is 1.5 to 1.7 million tons from electric utilities and is 1.4 to 1.6 million tons from nonutility sources. NAPAP OD judges that no value within those ranges is preferable to any other.

Question: Apparently, the EPA used the emissions data from its "National Air Pollutant Emissions Estimates, 1940-1987" in calculating the emissions credit for the non-utility sector...Is that right? Is that a credible source for such a calculation? Please explain. Have other government agencies, such as the Department of Energy, conducted trends reports? If so, would you please compare these different reports and critique the different methodologies used.

Answer: Yes, this was the source for EPA's non-utility emissions estimate. It is a credible source; versions of this document have been published since 1968. The 1980-1985 nonutility emissions decrease of 1.1 million tons from this reference (described as "EPA Trends") is included as the lower bound of the plausible range. Another trends analysis was conducted for NAPAP by ANL/DOE. Comparisons of the nonutility emissions estimates reported in the EPA and ANL/DOE trend analyses are presented in Figure 1. The NAPAP 1980 and 1985 emissions inventory estimates are also given in the figure. NAPAP OD bases its best judgment range of 1.4 to 1.6 million tons on the ANL/DOE estimates. The ANL/DOE nonutility emissions trends were deemed superior to the EPA estimates based on an evaluation of how the two methods compared on several important criteria (listed earlier in this letter under "Analysis Approach"):

Figure 1. Comparison of National Nonutility Emission Estimates from EPA Trends Analysis, ANL/DOE Trend Analysis and NAPAP Inventories (1980 and 1985)



- **Appropriateness of the methodology employed.** For most nonutility sources, the ANL methodology is based on an extrapolation of the emission estimates in the 1985 NAPAP inventory, which is generally regarded as the best available historical emissions estimate. The NAPAP OD prefers the ANL method to the EPA Trends approach which uses published industrial statistics and average, national-level emission factors and pollution control estimates.

- **Adequacy and representativeness of the input data.** The data used in EPA Trends for tracking industrial activity and fuel use over time is deemed to be reliable; however, the data on emission factors and removal efficiencies may not represent actual conditions. The ANL method, based on the 1985 NAPAP inventory, uses the best available emissions data and takes advantage of the reliability of the EPA data on industrial activity and fuel use trends, by employing growth rates based on EPA Trends values.

- **Degree of peer review.** Neither method has undergone complete review. The EPA Trends values, although widely used, have not been subjected to formal peer review outside EPA. The ANL/DOE methodology was subjected to peer review and formal NAPAP Emissions and Controls Task Group review in 1987. The ANL/DOE methodology was revised in 1989, and the changes have not been reviewed by the member agencies participating in the NAPAP Emissions and Controls Task Group. However, a third-party review contractor was employed by DOE to review the ANL/DOE method and its draft review report is available.

- **Estimated effects of systematic biases.** Both methods are poor at accounting for possible decreases in the sulfur content of coal used in the industrial sector and for plant-level operating changes and pollution-control initiatives that may have taken place between 1980 and 1985.

- **Comparability of the 1985 emission estimate to that in the 1985 NAPAP inventory.** For some individual industries and in total, the EPA Trends emissions estimates for 1985 are considerably different from those in the 1985 NAPAP inventory. The ANL/DOE values, being based on the inventory for most source categories, are much closer.

A more complete explanation of the strengths and weaknesses of the various nonutility trends estimates is included in notes [illegible] through [illegible] of Table 1.

Question: Relative to utility emissions, calculations and data analysis apparently were conducted by ICF, Inc. at the request of EPA. Is that right? Is the ICF data base for utilities accurate? Please explain.

Answer: Yes, ICF did provide EPA's utility data and projections. NAPAP OD judges the reported ICF estimate of the 1980-1985 reduction in emissions to be outside the plausible range (see notes [illegible], [illegible], and [illegible] to Table 1, and Enclosure 2). However, the adjusted ICF value (increased by 0.4 million tons to correct for the bias in application of emission factors for 1980 and 1985 -- see note [illegible]) is within the best judgment range. The future emissions projected by ICF appear reasonable, since ICF's estimates of 1985 utility emissions are fairly close to those in the 1985 NAPAP inventory (see note [illegible] to Table 1).

Question: Are the assumptions used in analyzing the impacts of the bill on emissions reductions appropriate? Please explain. In replying, it is not necessary to address the ICF model used in the analysis as the model is not at issue.

Answer: EPA prepared four scenarios comprised of combinations of two electricity demand growth cases and two levels of trading constraints. Given the high degree of uncertainty associated with future conditions, the EPA/ICF scenarios appear reasonable, although other sets of conditions might be considered equally possible. EPA and EEI projections of future growth in emissions are not radically different; therefore, the assumptions affecting future emissions do not appear to be controversial. NAPAP has not reviewed the assumptions affecting costs.

PART C - IMPORTANCE OF SMALL CHANGES IN EMISSION CONTROL TARGETS

Mr. David Finnegan of the Committee staff has asked that we also comment on the effect that changes in post-2000 emission targets of approximately one or two million tons would have on environmental conditions. We note that the uncertainties associated with the best estimates of the reductions projected to result from H.R. 3030 are in the range of one-half million tons (see Finding 2 in Part A of this letter).

In commenting on this question we note the following comparisons:

o maximum national SO_2 emissions (1973)	-- 31 million tons
o 1985 emissions (NAPAP inventory)	-- 23 million tons
o Post 2000 projection under H.R. 3030	-- 15 million tons

A one to two million ton change in the post 2000 emission target would be a change from the 15 million ton projection.

By February 9, 1990, we will provide a qualitative response to this question. As described in the NAPAP Assessment Plan Update (August 1989), we are analyzing the projected environmental outcomes for "sensitivity cases" of emission reductions both greater and less than the 10 million ton case. Because of the time needed to prepare, conduct, review and analyze the extensive calculations, the results of these sensitivity comparisons will not be available until June 1990 at the earliest. Our forthcoming qualitative comments will be based on NAPAP's consideration of the available measurement data, and of the theoretical modeling approaches.

I hope the information in this letter is responsive to your questions. We would be pleased to provide further information as you may request.

Sincerely,

John L. Malanchuk for

James R. Mahoney
Director

Enclosures

cc: Honorable Howard C. Nielson
Honorable Mitch McConnell

Table 1. Summary of the 1980 to 2000 National SO_2 Emission Changes Expected Under H.R. 3030†

The attached footnotes should be reviewed together with the table

	Emissions Change from 1980 (million tons)						
	EPA[a]	EEI[b]	ANL/DOE for NAPAP[c]	EPA Trends[d]	NAPAP Inventories[e]	Plausible Range[f]	Best Judgment[g]
Electric Utility Emissions							
• Total change: 1980-1985	-1.1[h]	-1.3[i]	-1.8[j]	-1.4[k]	-1.4[l]	-1.3 to -1.8[m]	-1.5 to -1.7[n]
• Affected units[o]: 1985-2000	-7.9 to -8.1[p]	-7.7[q]		NA	NA	-7.7 to -8.1[r]	-7.9[s]
• Nonaffected existing units: 1985-2000[t]	-0.03 to +0.36	-0.18 to +0.13[u]		NA	NA	-0.2 to +0.4[w]	0.0 to +0.3[x]
• New (post-1985) units to 2000 (net of offsets for post-enactment units)[y]	+0.28 to +0.31	+0.15 to +0.24	-7.7[v]	NA	NA	+0.2 to +0.3[z]	+0.2 to +0.3[z]
• Repowering adjustment[aa]	+0.03 to +0.15	0	NA	NA	NA	0.0 to +0.2[bb]	+0.0 to +0.2[cc]
• Operating margin adjustment[dd]	0	-0.5 to -0.6	NA	NA	NA	0.0 to -0.2[ee]	0.0 to -0.1[ee]
Subtotal: 1980-2000 utilities	-8.3 to -8.8*	-9.2 to -9.5*	NA	NA	NA	-8.4 to -9.8[ff]	-8.8 to -9.3[gg]
Non-utility Emissions							
• 1980-1985	-1.1[hh]	-2.7[ii]	-1.6[jj]	-1.1[kk]	-2.4[ll]	-1.1 to -1.9[mm]	-1.4 to -1.8[nn]
• Transportation decrease due to sulfur reduction: 1985-2000	-0.4[oo]	-0.5[pp]	NA	NA	NA	-0.3 to -0.4[qq]	-0.4[rr]
• Industrial, residential, commercial change: 1985-2000	0	-0.3[ss]	+0.1[tt]	NA	NA	+0.1 to -0.3[uu]	0[vv]
Subtotal: 1980-2000, non-utilities	-1.5	-3.5	NA	NA	NA	-1.4 to -2.5[ww]	-1.8 to -2.0
Total	-9.8 to -10.3	-12.7 to -13.0	NA	NA	NA	-9.8 to -12.3[xx]	-10.6 to -11.3[yy]

NA - Not Applicable

* Utility subtotals supplied by EPA and EEI do not equal the sums of the individual category values due to independent rounding.

† Information presented represents the judgment of the NAPAP Office of the Director.

Notes to Table 1

[a] Emissions from electric utilities were estimated by ICF for EPA. The emissions change for nonutility sources between 1980 and 1985 was taken from *National Air Pollutant Emission Estimates, 1940-1987* (U.S. EPA Report EPA-4504-88-022). The transportation emissions change, 1985-2000, was estimated by EPA. See Enclosure 3.

[b] Values shown were estimated by Temple, Barker, and Sloane (TBS), Inc. for Edison Electric Institute (EEI). See Enclosure 2.

[c] Estimates of emissions from utility and nonutility sources are from the "Month and State Current Emission Trends" (MSCET) data base prepared by Argonne National Laboratory (ANL) for NAPAP and updated annually since 1986. The ANL/DOE MSCET methodology was subjected to independent peer review by the NAPAP Peer Review Panel in March 1988. ANL has recently modified the trends methodology in four principal areas: (a) use of individual boiler information instead of plant-level information for electric utilities, (b) use of a different assumption about FGD utilization rates [the method now assumes FGDs operate only enough to meet applicable emission standards], (c) use of individual plant data for copper smelters, and (d) adoption of the NAPAP 1985 emissions inventory emission estimates for other source categories, except for the transportation category. A contracted third party peer review of the revised methodology has recently been completed, and a draft report is available. In addition, representatives of DOE and EPA have analyzed the modified ANL/DOE methodology as part of the analyses conducted in preparation of this table and EPA has posed questions on the methodology which they feel must be addressed as part of the forthcoming NAPAP review process. The internal NAPAP peer review of the ANL/DOE MSCET methodology changes is planned for February 1990. See Enclosure 6. The future projections of emissions were made using NAPAP's Integrated Model Set developed by EPA and DOE. The future utility scenario is similar but not identical to H.R. 3030 (Enclosure 6). It should be noted that: (a) In addition to these 1985 values, any method also requires 1980 values to enable a comparison to be made between years, (b) the Argonne method for calculating these 1980 values has been identified as one of the areas in which EPA has substantial questions, and (c) it has not been demonstrated to EPA's satisfaction that this methodology provides an advantage over other methods; this is one of the matters EPA hopes to explore in the forthcoming reviews.

[d] Values shown are taken from *National Air Pollutant Emission Estimates: 1940-1987* (U.S. EPA Report EPA-450/4-88-022). Versions of the EPA trends data have been prepared since 1968, and have been widely used by EPA and other organizations. Documentation of the 1989 version of the methodology is in an internal EPA document (hardcopy and PC diskette). The methodology and data have not been subjected to formal peer review. See Enclosure 5.

[e] Sources for estimates shown are: *The 1985 NAPAP Emissions Inventory (Version 2): Development of the Annual Data and Modelers' Tapes* (U.S. EPA Report EPA-600/7-89-012a), and *Development of the 1980 NAPAP Emissions Inventory* (U.S. EPA Report EPA-600/7-86-057a). See Enclosure 4.

(2) ANL used data on boiler-level emission standards from the 1985 EIA Form 767 for all years in the study period. This leads to inaccuracy in the 1980 values, since emission standards for some plants changed in the 1980-1985 time period. The inaccuracy (which could not been quantified) is probably in the direction of understating the 1980 emissions (i.e., it leads to an underestimate of the 1980 to 1985 decline). (3) "In addition, EPA has found that in some cases the emission standard information in Form 767 differs from the enforceable standard in place in 1985. ANL did not convert the reported standards to annual standards, which convert the reported standards to annual standards, whch would have resulted in lower emissions estimates. This matter should be explored as part of the forthcoming NAPAP review of the ANL methodology." (4) Use of Form 423 data for fuel sulfur content in 1980 results in an inconsistency with emissions values for 1985, which are based on EIA Form 767 data. (Form 423 provides data on sulfur content of fuel delivered; whereas Form 767 provides data on fuel consumed. The sulfur content of fuel delivered is on average slightly lower than the sulfur content of fuel consumed.) This could result in emission values for years other than 1985-1987 that are up to 1% too low (i.e., the estimate of the reduction between 1980 and 1985 might be understated); however, a precise estimate of the extent of the understatement cannot be made. (5) The ANL method is based on the assumption that FGDs are operated only enough to meet applicable emission standards, which does not account for the fact that some plants over-control. However, in a sensitivity run, ANL used the assumption that scrubbers are used at operating efficiencies, as reported on the 1985 DOE/EIA Form 767. The tonnage decrease in SO_2 emissions between 1980 and 1985 in this sensitivity run was the same as that from the regular methodology; therefore, the scrub-to-standard assumption does not appear to strongly influence the 1980-1985 trend. The ANL method does not account for scrubbers that were operating in 1980 but not in 1985.

[k] EPA trend values are computed on a national basis using national fuel consumption and fuel quality statistics as well as plant- and unit-level data to estimate national SO_2 removal from FGDs (FGDs are assumed to operate at design efficiency.) **Comments:** (1) Use of design, instead of actual, FGD removal efficiencies tends to underestimate the trend. (Since more control occurred in 1985 than in 1980, the underestimation of emissions caused by use of design rather than operating efficiency is greater in 1985 than in 1980.) (2) Calculations such as the one employed here, which are carried out at the national level, result in a less accurate answer, other things being equal, than those carried out at the boiler or generating-unit level.

[l] Utility emission estimates for the 1980 NAPAP Emissions Inventory were computed using standard emission factors and fuel statistics reported to DOE. For 1985, emissions estimates were derived primarily from data reported by states air pollution control agencies to EPA via the National Emissions Data System (NEDS). (The 1985 NEDS data were subsequently thoroughly checked as well as compared to and supplemented with DOE data.) **Comments:** (1) Boiler-level emission factors may differ in the two estimates, since the 1980 inventory used standard emission factors for all boilers and the 1985 inventory used state-supplied or plant-specific factors in some cases. The use of state- or plant-specific emission factors should improve the emissions estimates. (2) Design instead of operating efficiencies were used in the calculation of 1980 emissions,

probably resulting in an underestimate of emissions in 1980 and therefore, an underestimate of the 1980 to 1985 trend.

[m] The plausible range is bounded by the EEI and ANL/DOE estimates. The value developed by ICF for EPA, when adjusted by 0.4 million tons to correct the bias resulting from the use of different emission factors for the 1980 and 1985 estimates, becomes 1.5 million tons and falls within the plausible range (see note [k]). The EPA *Trends* estimate and the difference between the two NAPAP inventories (both 1.4 million tons) also fall within the plausible range.

[n] The lower bound of the NAPAP OD best judgment range is based on the 1980-1985 emissions decrease estimated by the EPA Trends analysis and the comparison of the two NAPAP inventories, increased by 0.1 million tons to reflect the possible bias introduced by their use of FGD design rather than operating efficiencies in one or both of the years. The lower bound is also equal to the ICF estimate for EPA, corrected for the bias in the application of the emission factor (1.1 + 0.4 = 1.5). The ANL/DOE estimate of 1.8 is judged by NAPAP OD to be based on an appropriate methodology and reliable data. For the upper bound of the best judgment range, the ANL/DOE value has been reduced by 0.1 million tons for conservatism, pending broader review. If ongoing reviews indicate no problems with the ANL/DOE estimate, it would be appropriate to revise the best judgment upward. The EEI trend value is not in the best judgment range because of possible inaccuracies in the 1985 values and inconsistency in the estimation method for 1980 and 1985 (see note [l]).

[o] "Affected units" in H.R. 3030 are those units with capacity of 75 MW or greater and emission rates of 1.2 lb/MMBtu or greater in 1985.

[p] EPA examined four scenarios. Two of these were "constrained" cases, in which full trading was not assumed to occur. These cases resulted in higher emission reductions since some states require more control than H.R. 3030; in these constrained cases the extra reduction could not be traded and used by others. Comment: H.R. 3030 allows full trading; therefore, NAPAP OD has adopted the flexible cases in the best judgment estimate. To the extent that full trading does not occur, the emission reductions would be larger than those NAPAP OD has included in the best judgment estimate.

[q] Comment: The estimate of 1985 emissions from "affected units" in the TBS data base is lower than that in the 1985 NAPAP inventory or in the ICF data base (see note [l]). This may be the reason why the TBS estimate of the reduction due to the requirements of H.R. 3030 (7.7 million tons) is lower than EPA's (7.9 million tons).

[r] The full range of the projected decrease -- from 7.7 (estimated by TBS) to 8.1 (the constrained case estimated by EPA) -- is deemed plausible.

[s] Because ICF's estimate is based on 1985 emissions for various categories of utility units that are closer to those cited in the 1985 NAPAP Emissions Inventory, the EPA estimate is judged to be the best estimate. Independent estimates carried out by EPA based on the 1985 NAPAP Inventory emission rates

and the 1985-87 average fuel consumption from Form 767 confirmed that the reduction would be approximately 7.9 million tons.

[t] Emissions from small units (with capacity less than 75 MW) are expected to decrease due to retirements, and emissions from units with emission rates less than 1.2 lb/MMBtu are expected to rise as a result of increases in capacity factors. The values shown are the net result of these two trends. Ranges are shown because both high and low growth scenarios were analyzed by ICF and TBS.

[u] The estimate of emission decreases due to retirements of units under 75 MW by TBS is higher than that by ICF, possibly because the TBS 1985 emissions value for such units is higher. See note [l].

[v] The NAPAP Integrated Assessment will analyze a series of emission scenarios, one of which calls for a 1.2 lb/MMBtu emission rate requirement on all electric utility units over 75 MW. The principal features of this NAPAP scenario that are different from H.R. 3030 are the following: it is based on an emission rate curtailment, not an allowance system; no trading of allowances occurs; capacity factors can increase without emissions being offset; and no offset of emissions is required for new units. Furthermore, the 1985 values from which the 1985-2000 trend is calculated are projected by the model and are approximately 0.6 million tons higher than the calculated estimate for 1985. NAPAP OD is using the results of this scenario only as a rough approximation of the magnitude of the emissions reduction resulting from H.R. 3030.

[w] The plausible range presents the maximum and minimum values from the combined analyses of EPA and TBS.

[x] NAPAP OD's best judgment range favors the EPA estimates, since they appear to be based on a better estimate of 1985 emissions in this category of sources.

[y] Units coming on line between 1985 and enactment of H.R. 3030 would not be subject to the new source offset provisions, and therefore, will cause some level of emissions increase. Estimates of this increase do not vary much between the ICF/EPA and TBS/EEI projections.

[z] The full range projected by the combined ICF (EPA) and TBS (EEI) analyses is presented as both the plausible range and best estimate. The projections differ primarily because of differences in the projected capacity factors of the units in question. NAPAP OD has no basis for narrowing this range, since determining future capacity factors of these units is speculative and must be determined using a model driven by assumptions about the future.

[aa] The EPA projection includes an estimate of the increase in emissions that would result if units meet the 1.2 lb/MMBtu emission limit by repowering, thus receiving permanently higher allowances. (The estimate presented here excludes the temporarily higher emissions in the period from 2000 to 2003 that result from the postponement until 2004 of reductions from repowering units.)

[bb] The plausible range is adopted from the EPA estimates. NAPAP OD has no independent estimates of increased emissions from repowered sources under H.R. 3030 upon which to base any changes to this range.

[cc] The best estimate range is also adopted from the EPA estimates, for the reason stated in note [bb].

[dd] TBS and EEI assert that utilities will operate their units below the emission level required under their allowances in order to assure they will be able to meet their allowances without risk of non-compliance.

[ee] NAPAP OD agrees that utilities might initially "bank" emission credits, but believes they would not continue this practice once an adequate margin of safety had been banked in the first few years. Thus, there may be a significant emission reduction in 2000-2003, but the reduction would be lower in years thereafter. NAPAP OD rejects the concept of an annual operating margin set-aside in the range of 10% of annual emissions from affected sources, as asserted by EEI, but believes it is appropriate to annualize the emissions banked in the first few years over a longer period of time, such as ten years. A plausible range for such an annualized operating margin decrease is judged by NAPAP OD to be 0.0 to 0.2. NAPAP OD's best judgment for the annualized range is lower -- 0.0 to 0.1.

[ff] The combination of maximum and minimum values of the component ranges yields a range of -8.1 to -10.1. The range has been narrowed by 0.3 at each end, to -8.4 to -9.8, to reflect the improbability that the extreme bounds of the component ranges would occur simultaneously in the same direction. The midpoint of this range is -9.1.

[gg] The combination of maximum and minimum values of the component ranges yields a range of -8.6 to -9.5. The range has been narrowed by 0.2 at each end, to -8.8 to -9.3, to reflect the improbability that the extreme bounds of component ranges would occur simultaneously in the same direction. The midpoint of this range is -9.05.

[hh] This value was taken directly from the "EPA Trends" analysis, reported in the fourth column of the table. Values are based on national-level computations that account for trends in fuel use and industrial production and use standard emission factors. A minimal level of pollution control is assumed to occur in the nonutility sectors. **Comments:** (1) The 1985 emission estimates obtained by the EPA Trends analysis for the nonutility sector are considerably higher than those in the 1985 NAPAP Emissions Inventory, particularly in the industrial process category (for which the EPA Trends value is over 25% higher than the 1985 NAPAP inventory value). The 1985 NAPAP inventory is generally considered to be the better of the two estimates, since it contains detailed information of each emissions source, including plant-specific data on factors that can affect emissions. The large magnitude of the differences between the EPA Trends emission values and those in the 1985 NAPAP inventory calls into question whether the EPA Trends method adequately accounts for all of the factors that influence emission levels and, hence, emission trends. The principal disadvantage of the methodology is its reliance on average, national-level emission factors (ratios of emissions to activity) and pollutant removal efficiencies, whose uncertainties are of first-order importance in calculating emission trends. (2) The principal advantage of the EPA Trends method is the consistency of its estimation procedure for every year.

[ii] TBS obtained this value by subtracting the nonutility emissions in an early version of the 1985 NAPAP Emissions Inventory from the nonutility emissions in the 1980 NAPAP Emissions Inventory. **Comment:** The 1980 NAPAP Emissions Inventory was not subjected to the level of quality control/assurance to which the 1985 inventory was subjected. Hence, the 1980 inventory is prone to systematic errors that lead to overestimation of emissions. These include: (a) many plants report data for years earlier than 1980, when emissions were higher; (b) fuel use appears to be over-reported; (c) some states are thought to have reported allowable rather than actual emissions for some sources; (d) comparison of the two inventories yields implied emission decreases in some states and industries that appear unreasonably high. Without repeating the 1980 inventory process, it is impossible to fully quantify the level at which emissions were overestimated in the 1980 inventory. Some quantitative analyses of the problems have been carried out; they indicate a range of possible overestimation, but they are not definitive. One such analysis by EPA indicates that the non-1980 year of record problem [item (a) above] could have led to an overestimation of approximately 0.3 million tons. Analyses of the other problems suggest a possible overestimation of an additional 0.6 million tons [Item (b) above has not been included in this value because fuel use appears to be overreported in both the 1980 and 1985 NAPAP inventories]. This indicates a possible total overestimate of 0.9 million tons. This cumulative bounding evaluation is itself likely overestimated because of double counting in some of its components. Other semi-quantitative evaluations (i.e., consistency checks) of possible overestimates in the 1980 NAPAP inventory can be developed by comparison of the inventory value (9.47 million tons) with the EPA and ANL/DOE trends estimates for 1980. These comparisons suggest an overestimate in the range of 0.7 to 1.0 million tons; however, this cannot be considered a reliable estimate. In sum, NAPAP OD concludes that comparison of the 1980 and 1985 NAPAP inventories overstates the 1980-1985 reduction in emissions, and that the estimates of the overstatement should be viewed as general indicators of the magnitude.

[jj] Values are from the MSCET analysis conducted by ANL/DOE for NAPAP. Except for copper smelting and transportation sources (which are estimated independently) the MSCET values are based on the 1985 NAPAP inventory values for emissions in various sectors, to which growth rates derived from the EPA Trends analysis (see note [mm]) are applied to obtain 1980 values. **Comments:** (1) The use in the MSCET methodology of the 1985 NAPAP inventory values, which are judged to be the best estimate of nonutility emissions in 1985, gives the MSCET methodology an advantage over other aggregate trends estimation methods (e.g., the EPA Trends method -- see note [mm]). (2) Values are preliminary, pending completion of the NAPAP internal review of the 1989 MSCET methodology changes. (3) The 1980-1985 trend estimated by the MSCET analysis may be biased toward underestimating, since it does not consider reductions in coal sulfur content and other plant-level operating changes that may have resulted in an emission decline. Using the decrease in the average sulfur content of coal supplied to utilities as a guide to the reduction that may have taken place in the industrial sector, the MSCET estimate may underestimate the emissions decrease between 1980 and 1985 by as much as 0.3 million tons. Comparison of data records in the 1980 and 1985 NAPAP inventories support the suggestion that a decrease in the sulfur content of fuel in the industrial sector may have occurred between 1980 and 1985. (4) The current version of the MSCET values are based on the version of the 1985 NAPAP inventory before its final adjustments in the last round of quality

control. Therefore, the MSCET values for 1985 do not exactly match the published values from the inventory. See note [45], NAPAP comment (2). (5) It should also be noted that: (a) In addition to these 1985 values, any method also requires 1980 values to enable a comparison to be made between years, (b) the Argonne method for calculating these 1980 values has been identified as one of the areas in which EPA has substantial questions, and (c) it has not to our knowledge been demonstrated to EPA's satisfaction that this methodology provides an advantage over other methods; this is one of the matters EPA hopes to explore in the forthcoming reviews.

[44] See note [47].

[45] Comparison of the nonutility SO_2 emissions estimate from the 1980 NAPAP inventory to the published value from the 1985 NAPAP Inventory (Version 2) yields an implied decrease of 2.4 million tons. Comment: (1) Comparison of the two inventories does not yield the best estimate of the trend between 1980 and 1985. The 1980 inventory contains a series of systematic problems -- see note [43]. (2) The final adjustment of the 1985 inventory resulted in the double-counting of emissions by approximately 0.2 million tons, implying a more appropriate difference of 2.6 million tons between the 1980 and 1985 inventory values.

[46] The EPA Trends value is adopted as a minimum value for the plausible range. An upper bound for the plausible range is judged to be 1.9 million tons, which is derived from two considerations: (1) it is 0.3 million tons above the ANL/DOE (MSCET) computed decrease, to account for the possible effect of sulfur content decreases and other plant-level emission controls (see note [43]), and (2) it is 0.7 million tons below the adjusted NAPAP inventory difference figure of 2.6 million tons [see note [45], NAPAP comment (2)]. This upper limit to the plausible range is 30% lower than the originally reported difference in the 1980 and 1985 NAPAP inventories (2.7 million tons).

[47] NAPAP OD judges that best estimate for nonutility trends is provided by the MSCET methodology, which applies 1980-1985 percentage changes in activity levels (derived from the EPA Trends analysis) to the corresponding emission values from the 1985 NAPAP inventory. It is possible that the MSCET value understates the actual trend in emissions, since it does not include the effect of the possible change in coal sulfur content or other plant-specific operating changes that might resulted in a more pronounced emissions decrease (see note [43]). However, the MSCET values are preliminary, pending completion of the NAPAP internal review of the 1989 MSCET methodology changes. Thus, to be conservative, for the NAPAP best estimate, the MSCET 1980-1985 trend has not been increased by the possible effect of a sulfur-content decline. Furthermore, to reflect the uncertainty of historical nonutility emission trends, a range is provided for the best estimate. The lower bound of the best judgment range is set at 0.2 million tons lower than the MSCET 1980-1985 difference, which represents a level of uncertainty of approximately 10%.

[48] The value is based upon an EPA calculation, included in Enclosure 3. EPA recommended using the value of -0.4 million tons, which is rounded from the upper bound of their calculated range. The lower bound is -0.25. See Enclosure 3. Comment: The analysis done by EPA appears reasonable. NAPAP OD has not carried out an independent analysis to estimate this value.

[pp] The value estimated by TBS is based on an earlier EPA estimate. TBS has not carried out an independent estimate of this value.

[qq] The EPA range of estimates is adopted as the NAPAP OD plausible range.

[rr] EPA's best judgment of 0.4 million tons is accepted by NAPAP OD.

[ss] TBS cites an EPA report that presents projections for nonutility sources. A decrease of 0.3 million tons is cited in the report. TBS also cites an internal EPA memorandum, which documents a post-1985 decrease of 0.3 million tons from smelters.

[tt] As an example of possible future conditions, a scenario to be included in the NAPAP Integrated Assessment results in a nonutility emissions increase of 0.1 million tons.

[uu] NAPAP OD adopts the two cited projections as a plausible range.

[vv] Future emissions from nonutility sources are highly uncertain. Such emissions are influenced by many economic and energy-related factors. The projections cited by TBS and those made by ANL use different models and assumptions for these factors, which explains the discrepancy. H.R. 3030 does not require offsets of emissions growth for nonutility sources; therefore, emissions may rise. On the other hand, emissions might decrease as a result of certain future conditions, such as lower natural gas prices; these conditions may be temporary, and hence emissions might increase again. Decreases in emissions from smelters have already been partially offset by increases from other industries. Because of the uncertainty associated with future nonutility emissions, NAPAP OD does not recommend that a decrease in emissions from nonutility sources be included in the total reduction expected under H.R. 3030.

[ww] The combination of the maximum and minimum values of the component ranges yields a range of -1.3 to -2.6 million tons. The range has been narrowed by 0.1 at each end to reflect the improbability that the extreme bounds of the component ranges would occur simultaneously in the same direction. The midpoint of the range is -1.95.

[xx] The range for the total is represented by the sum of the upper bounds of the utility and nonutility ranges and the sum of the lower bounds of the two ranges. The midpoint of the range is 11.05 million tons.

[yy] The range for the total is represented by the sum of the upper bounds of the utility and nonutility ranges and the sum of the lower bounds of the two ranges. The midpoint of the range is 10.95 million tons.

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

722 JACKSON PLACE, N.W.
WASHINGTON, D.C. [illegible]
202/[illegible]

February 7, 1990

Honorable John D. Dingell
Chairman, Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Dingell:

Mr. David Finnegan of the Committee staff has asked that we comment on the effect that changes in post-2000 emission targets of approximately one or two million tons would have on environmental conditions. We acknowledge this request in our February 5 response to you and are providing additional information now as promised.

We note that uncertainties associated with best estimates of the reductions projected to result from H.R. 3030 are in the range of one-half million tons (see Finding 2 in Part A of my February 5 letter to you).

In commenting on this question we also note the following comparisons:

- o maximum national SO_2 emissions (1973) -- 31 million tons
- o 1985 emissions (NAPAP inventory) -- 23 million tons
- o Post 2000 projection under H.R. 3030 -- 15 million tons

A one or two million ton change in the post 2000 emission target would be a change from the 15 million ton projection constituting a 7% to 13% change in emissions.

As described in the NAPAP Assessment Plan Update (August 1989), we are analyzing the projected environmental outcomes for "sensitivity cases" of emission reductions both greater and less than the 10 million ton case proposed in H.R. 3030. Because of the time needed to prepare, conduct, review and analyze the extensive calculations, the results of these sensitivity comparisons will not be available until June 1990 at the earliest.

The following qualitative comments are based on the best judgment of NAPAP Office of the Director's (OD's) consideration of the available measurement data, and of the theoretical modeling approaches. While our response has been reviewed by the NAPAP participating agencies, it does not represent an adopted position of those agencies.

Honorable John D. Dingell

- We recognize that the President and his policy officials, together with the Congress, must weigh the balance between marginal changes in benefits and marginal changes in costs. As far as environmental benefits alone are concerned, greater emission reductions would always be preferred, compared to lesser reductions.

- If emissions or deposition were to change by 7% to 13%, the regional patterns of the effects of concern (e.g., aquatic systems, high elevation red spruce, materials degradation, health risks and visibility degradation) would likely change, but such changes would not likely be measurable. It is unlikely that differential environmental effects over large regions could be measured between cases where the national emission levels would differ by one or two million tons. However, if such differences in emission levels were concentrated within a small region, then distinctive differences in environmental effects within the region might be observed.

- Even when regional differences in effects (related to small differences in emission levels) are difficult to measure over periods of several years, such differences may occur and be observed over longer periods such as decades.

I hope the information in this letter is responsive to your questions. We would be pleased to provide further information as you may request.

Sincerely,

John L. Malanchuk

James R. Mahoney for
Director

Enclosures

cc: Honorable Howard C. Nielson
Honorable Mitch McConnell

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SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
FEB 12 1990
WASHINGTON, D.C. 20510

The Honorable J. Bennett Johnston
Chairman, Senate Committee on
Energy and Natural Resources
Room 364, Dirksen Senate Office Bldg.
Washington, D.C. 20510

February 9, 1990

Dear Senator Johnston:

This is in response to your letter of January 29, 1990 requesting that I respond in writing to certain questions propounded by Senators Ford and McClure in connection with the January 24, 1990 acid rain hearing. My written responses are attached.

Very truly yours,

A. Joseph Dowd

A. Joseph Dowd

Attachments
AJD/lz
cc: The Honorable Wendell H. Ford
The Honorable James A. McClure

A. Joseph Dowd
Senior Vice President
and General Counsel

John F. DiLorenzo, Jr.
Vice President, Secretary
and Associate General Counsel

John B. Shinnock
Jeffrey P. White
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QUESTION FROM SENATOR FORD

Q. What impact will the emissions cap have on the future use of coal?

A. Because of the emissions cap, all new power plants which go into service after the enactment of the legislation must offset their SO_2 emissions 100% by January 1, 2000 (S. 1630). Assuming enactment before the end of this year, this means that all such facilities that go into service during the nine-year period 1991-1999 must on the very same day -- New Year's Day 2000 -- offset their SO_2 emissions 100%.

Now put yourself in the place of a single-project IPP or a single-project QF which wishes to place a generating facility into service during the early 1990's. It has no allowances. If it is unable to obtain allowances by the end of the decade it will have to shut its facility down with a resulting loss of its investment. Should it assume the risk and go forward and construct the project before it has nailed down its allowances? Will the utilities be in a position to commit allowances during the early, mid or even late 1990's? (It seems unlikely.) And if so, what will the allowances cost? Common sense indicates that the developer must know that he will be able to acquire the necessary allowances at a price that will not destroy the project's economics before he goes forward with the project. We do not believe that this assurance and the necessary information will be available to the developer until the late 1990's at the earliest.

Under the circumstances, IPP and QF developers will avoid these formidable risks by simply turning to non-SO_2-emitting natural gas to fuel their new facilities.

The natural gas expedient will not be confined to the IPP's and the QF's, but will of course be utilized on a much grander scale by all entities which lack allowances and which are unable to generate such allowances themselves. Thus natural gas will be the fuel of choice for utilities throughout the Southwest and in other "low emitting" regions of our nation.

The Administration bill (H.R. 3030 and S. 1490), on which S. 1630 is in very large part based, was consciously crafted by U.S. EPA to promote the use of natural gas. EPA has characterized it as a "pro gas bill". In an address to the Natural Gas Roundtable, U.S. EPA Assistant Administrator William Rosenberg stated that, "I don't think we could have written it any stronger for your industry, and we did it very intentionally" (emphasis supplied). See the attachment from the November 13, 1989 issue of Inside FERC.

S. 1630 further tilts toward use of natural gas. In the NO_x allowance program established in Sec. 407 of S. 1630 as reported out of committee, only coal-fired utility boilers would be subject to a permanent cap on NO_x emissions.

Since our nation's most abundant energy resource is coal (with a 300 to 400-year reserve in the ground), it is not good national energy policy to adopt major legislation that will cause our nation to turn its back on it's most abundant energy resource in favor of a fuel that is much more limited in supply and which historically has been subject to volatile price fluctuations.

While the high and the low sulfur coal interests have been jockeying for advantage with respect to this legislation, they have failed to see the "big picture", i.e., that this legislation will, even in the near-term, prove to be disastrous for the coal industry as a whole. As an illustration, AEP in its various approaches to compliance is giving very serious consideration to switching not to low sulfur coal, but to natural gas, at a number of its older, smaller units.

INSIDE FERC - November 13, 1989

THE BUSH ADMINISTRATION'S CLEAN-AIR PLAN IS TAILORED TO GAS USE, Environmental Protection Agency Assistant Administrator William Rosenberg told the Natural Gas Roundtable last week. At the group's monthly luncheon in Washington, Rosenberg maintained that "I don't think we could have written it any stronger for your industry, and we did it very intentionally." He called the administration's proposed amendments to the Clean Air Act a "clean-fuels bill, and very appropriately a pro-gas bill."

Because gas is domestically produced and is a clean and economic fuel, "there really is no reason why public policy should not promote it," Rosenberg asserted. "In fact, there is every possible reason why, from an energy point of view, from an environmental point of view and an economic point of view, public policy should make it easier to use gas."

Acknowledging the gas industry's concern about the possibility of the adoption of cost-sharing provisions to finance the cleanup, like a tax on electricity production (*IF*, 18 Sept, 11), Rosenberg sought to allay that fear. He reported that a Nov. 3 letter from White House Chief of Staff John Sununu to Rep. Henry Waxman, D-Calif., set out "in the strongest terms that I have seen out of the White House" the administration's flat opposition to any cost sharing through a fee or a tax. "We share your trepidation," Rosenberg told the industry officials, but "we don't think the votes are there to secure cost sharing and the administration could not be clearer in its position."

QUESTION FROM SENATOR FORD

Q. What impact will the compliance dates in the legislation have upon the clean coal technologies program?

A. The compliance dates contained in the Administration's bills (H.R. 3030 and S. 1490) will inevitably inhibit the development of the clean coal technologies (CCT).

With respect to the Phase 1 compliance date of 12/31/95, to the extent that technology is employed in achieving the Phase 1 emission reductions, that technology will inevitably have to be conventional, off-the-shelf, sludge-producing scrubbers. The time frame simply will not permit the deployment of the major innovative clean coal repowering technologies in Phase 1. To the extent that Phase 1 plants are retrofit with scrubbers, such plants will not later be available to incorporate the CCT's when the CCT's eventually do become commercially available. Also, the dollars spent on conventional scrubber retrofits in Phase 1 will not be available for use by utilities in fostering the development of the CCT's.

With respect to Phase 2, an effort is made in the Administration's bills to help the CCT program by incorporating regulatory incentives and by granting an extension of the Phase 2 compliance date (12/31/2000), but only in situations where CCT is employed. While this three year extension for CCT is helpful, it does not address the basic problem posed by the Phase 2 deadline, i.e., the fact that the decision as to whether to install conventional scrubbers or CCT must be made in 1995 (1996 at the very latest) so that if scrubbers are chosen, they may be installed by 12/31/2000. (The design, fabrication, shipment, installation and cut-in of scrubbers will require four to five years.) Unfortunately, the major repowering CCT's will not be commercially demonstrated for mass deployment until 1998-2000. Therefore, risk averse utilities forced to decide in 1995-96 will, we believe, play it safe and opt for conventional scrubbers. This could have the effect of delaying CCT development and deployment by several decades.

To the extent that utilities feel constrained to opt for proven over unproven technologies in the 1995-96 decision-making period, the three-year extension for CCT's as well as the regulatory incentives afforded CCT's in the legislation, of course, become academic.

An extension of the CCT compliance date to 2005 or 2006 would, however, give the utilities greater confidence by greatly reducing the risk that they would be unable to complete CCT projects on time. With such an extension of the CCT compliance date, utilities would be more inclined to opt for CCT's over conventional scrubbers, and the problem referred to above would be at least partially overcome.

What I have said up to this point relates to the compliance dates contained in the Administration's bills (H.R. 3030 and S. 1490) and would apply in spades to S. 1690 which cuts the Phase 1 and Phase 2 compliance periods by one year. Not only will CCT be ruled out by S. 1630's Phase 1 compliance date of 1/1/95, but it is likely that many major scrubber retrofits could not be completed by that time. S. 1630's earlier Phase 2 compliance date (1/1/2000) has the effect of moving the scrubber vs CCT decision date from 1995-96 to 1994-95 and, consequently, drives yet another nail in the coffin of CCT.

In order to provide CCT with breathing room in which to develop, what is really needed is a 3-year extension of the full Phase 2 compliance date contained in H.R. 3030 and S. 1490. This would allow the scrubber-CCT decision date to be moved from 1995-96 to 1998-99. By that time it is expected that the major repowering CCT's will have been commercially demonstrated. I recognize that the year 2000 Phase 2 compliance date is generally regarded as inviolable. Nevertheless, Dr. James Mahoney, the Director of NAPAP, in a memorandum dated 4/26/89 indicated that an extension of the Phase 2 deadline would be quite helpful to the CCT program and, on the basis of present scientific knowledge, would not be prejudicial to environmental values. A copy of Dr. Mahoney's memo is attached.

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

722 JACKSON PLACE, N.W.
WASHINGTON, D.C. 20503
202/395-5771

April 26, 1989

MEMORANDUM

TO: Nancy Maloley
Associate Director
Office of Economic and Domestic Policy

FROM: James R. Mahoney
Director, NAPAP

SUBJECT: Short Briefing Notes on Technical Acid Rain Issues

In response to your request today, I am attaching a short briefing statement on technical aspects of the acid rain control issue.

Because of the short time available, I have not been able to review this statement with the representatives of the NAPAP agencies. I am sending information copies to the NAPAP agency representatives at this time, and I will advise you promptly if any substantial disagreement arises during their review of these notes.

Attachment

Copies to: Interagency Science Committee
Interagency Policy Committee

NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

Briefing Notes -- April 26, 1989

James R. Mahoney

BACKGROUND

NAPAP was established under the authority of the Acid Precipitation Act of 1980 (PL 96-294) to develop the technical information needed for policy decisions pertaining to acid rain. NAPAP's research and assessment expenditures have exceeded $450 million since program activity began in 1982.

PL 96-294 requires NAPAP to analyze acid rain causes, effects and control strategies, by conducting policy relevant (1) scientific studies, (2) technology evaluations, and (3) economic analyses.

The principal NAPAP participating agencies include EPA, DOE, USDA, NOAA, DOE and CEQ. NAPAP is directed by a Joint Chairs Council chaired by the EPA Administrator and including a senior Presidential Appointee from each of the other five key agencies.

BENEFITS OF ACID RAIN CONTROL

The only benefits generally agreed to be expected from new acid rain controls will be improvements in acidic and sensitive lakes and streams. There is no consensus that improvements in other effects categories would be significant. Possible health risks associated with the acid rain pollutants (acid aerosols) are currently being evaluated. Improvements in degradation of exposed materials and in atmospheric visibility would occur, but may not be large. There is no evidence of widespread forest damage from acid rain, with the possible exception of mountaintop exposures to acidic clouds. (Ozone can cause forest damage in some regions, but SO_2 controls will not improve such ozone damage.)

Recent studies indicate possible lake and stream impacts throughout the East (i.e., not limited to the northeastern United States and southeastern Canada). This suggests that a control strategy highly focused on Ohio Valley and other midwestern power plants may not be optimal.

The time scale for either further acidification or recovery of lakes and streams is believed to be long (e.g., decades) in the Northeast, and is still being evaluated for other eastern regions. Insofar as the time scale for changes is long, control strategies which make significant use of clean coal technologies (CCT) are perferred, compared to retrofit scrubbers.

CONTROL STRATEGY IMPLICATIONS

CCT has several benefits compared to retrofit scrubber use, including energy efficiency (beneficial for global climate impacts), significant NO_x emission reductions, and more manageable wastes. If no critical acid rain effects are demonstrated to require more rapid control, a post-2000 (e.g., 2003-2005) deadline for full control implementation should be considered, to allow adoption of CCT options for many repowering applications.

A flexible specification of control requirements (examples: a two-phase approach with an updated evaluation in the mid-1990s, and marketable emission reductions) would optimize the benefits achieved by the national investment in controls.

NAPAP ASSESSMENT REPORTS

The NAPAP assessment reports to be completed during 1989 and 1990 will provide the following:

- Findings of the major scientific and technological studies now underway. Some changes in current information about effects, benefits and control technology are likely to result.

- Critical review and consensus building for the many disputed views about acid rain effects and control approaches. (The NAPAP International Conference on Acid Rain scheduled for February 1990 will be a major consensus building activity.)

- Comparative evaluation of control strategies, to report the most effective and cost efficient options.

QUESTION FROM SENATOR McCLURE

Q.1. The Clean Coal Coalition has recommended that the extension in the Phase II compliance deadline for certain clean coal technologies, which is currently set at December 31, 2003, should be extended until the year 2005. Can you please explain why a five year, rather than a three year extension is warranted? What benefits would be realized through such an extension, and do such benefits justify the possibility of greater emissions for an additional two years?

A. (a) American Electric Power is in a particularly good position to explain why a five, rather than a three, year extension for clean coal technologies is warranted. We are pioneering the pressurized fluidized bed combustion (PFBC) technology. Our 70 megawatt PFBC demonstration project at our Tidd Plant in Ohio will go into service this year. After benefiting from several years of operating experience at Tidd, construction will begin on a 330 megawatt commercial-scale PFBC repowering project at our Sporn Plant in West Virginia which repowering project is expected to go into service in the 1997-98 period. At least one year's successful operating experience at Sporn will be required in order to prove PFBC's commercial acceptability in the utility market. Thus, even if, in order to accelerate the process, permitting and design work were to go forward prior to Sporn's operation, the commercial deployment of PFBC units to achieve Phase II reductions could not be completed by 2003. We have estimated that the permitting, engineering and design and construction process for a commercial PFBC plant would take seven years. This is to be compared with eight years of lead time for a conventional coal-fired plant. However, if the deadline for CCT were moved to 2005 there would be a high degree of confidence that such CCT projects would be completed before that deadline. Thus, if the deadline remains at 2003, other utilities will not be able to avail themselves of our experience with commercial scale PFBC at Sporn; whereas if the deadline is extended to 2005 a much greater willingness will exist to go with the new technology. Even those who otherwise might opt for conventional scrubbing over CCT (when forced to make that decision in 1995-96) might be swayed by the extension of the CCT compliance date to 2005 to await the results of the Sporn experience.

(b) With respect to the benefits and (environmental) costs that would result from such an extension, I refer you to Appendix B to my filed testimony in which EPRI compares costs and benefits of the acid rain Title of H.R. 3030 with those of a vigorous CCT program. The EPRI study, in summary, states that both approaches will achieve a 50% reduction in SO_2 emissions within 40 years, but that the CCT approach will cost the nation $120 billion less than H.R. 3030. The CCT approach would reduce CO_2 emissions by up to

4% and solid wastes by up to 17% by 2050 while at the same time improving the efficiency of power generation by 4%.[*] Insofar as other environmental effects are concerned, the difference between the two approaches would be virtually indiscernible. On this basis, the negative environmental effects of a two-year extension of the CCT compliance date would be so inconsequential as to be immeasurable.

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[*] We have estimated that the permitting, engineering and design and construction process for a commercial PFBC plant would take seven years. This is to be compared with eight years of lead time for a conventional coal-fired plant.

QUESTION FROM SENATOR McCLURE

Q.2. Consideration is being given in discussions between Senators Byrd and Mitchell to confining Phase I to a limited number of plants (18-20). How would such a program impact your company?

A. As stated at page 11 of my filed testimony

> "...should the Senate revert to a 20-plant Control program in Phase I (which we understand is also under consideration), then real, non-cosmetic cost-sharing, i.e., a non-graduated tax on generation, would become absolutely essential. To impose the entire Phase I reduction burden on the customers of only 14 or 15 utilities without some form of true cost-sharing would be so grossly unconscionable as to verge on being cruel. Such a program would be in the nature of a major national environmental experiment which clearly would justify national funding. We would hope that any consideration of a 20-plant approach would recognize true cost-sharing as an absolute imperative."

The 18-20 plant proposal that surfaced several weeks ago contains an additional inequity. It would require the targeted plants to meet an SO_2 emission limitation of 1.1 lbs. per million Btu in 1995. This is a more stringent limitation than all other affected plants would have to meet. To exacerbate this inequity, these 18-20 targeted plants would have to meet this more stringent control requirement five years earlier than everyone else. Four AEP plants aggregating 5,255 megawatts are on this list. All four are owned by one of AEP's subsidiaries -- Ohio Power Company -- which serves the heavy industrial base of the Ohio River Valley. This highly concentrated impact upon one company, coupled with a lower emission rate than everyone else, which lower emission rate has to be met five years before everyone else, would result in a grossly unfair application of the law. This glaring inequity could only be overcome by some form of significant and non-cosmetic cost sharing such as a flat generation tax. A tax credit might also prove helpful in this respect.

QUESTION FROM SENATOR McCLURE

Q.3. What impact will the emissions cap have on the future use of coal?

A. Because of the emissions cap, all new power plants which go into service after the enactment of the legislation must offset their SO_2 emissions 100% by January 1, 2000 (S. 1630). Assuming enactment before the end of this year, this means that all such facilities that go into service during the nine-year period 1991-1999 must on the very same day -- New Year's Day 2000 -- offset their SO_2 emissions 100%.

Now put yourself in the place of a single-project IPP or a single-project QF which wishes to place a generating facility into service during the early 1990's. It has no allowances. If it is unable to obtain allowances by the end of the decade it will have to shut its facility down with a resulting loss of its investment. Should it assume the risk and go forward and construct the project before it has nailed down its allowances? Will the utilities be in a position to commit allowances during the early, mid or even late 1990's? (It seems unlikely.) And if so, what will the allowances cost? Common sense indicates that the developer must know that he will be able to acquire the necessary allowances at a price that will not destroy the project's economics before he goes forward with the project. We do not believe that this assurance and the necessary information will be available to the developer until the late 1990's at the earliest.

Under the circumstances, IPP and QF developers will avoid these formidable risks by simply turning to non-SO_2-emitting natural gas to fuel their new facilities.

The natural gas expedient will not be confined to the IPP's and the QF's, but will of course be utilized on a much grander scale by all entities which lack allowances and which are unable to generate such allowances themselves. Thus natural gas will be the fuel of choice for utilities throughout the Southwest and in other "low emitting" regions of our nation.

The Administration bill (H.R. 3030 and S. 1490), on which S. 1630 is in very large part based, was consciously crafted by U.S. EPA to promote the use of natural gas. EPA has characterized it as a "pro gas bill". In an address to the Natural Gas Roundtable, U.S. EPA Assistant Administrator William Rosenberg stated that "I don't think we could have written it any stronger for your industry, and we did it very intentionally" (emphasis supplied). See the attachment from the November 13, 1989 issue of Inside FERC.

S. 1630 further tilts toward use of natural gas. In the NO_x allowance program established in Sec. 407 of S. 1630 as reported out of committee, only coal-fired utility boilers would be subject to a permanent cap on NO_x emissions.

Since our nation's most abundant energy resource is coal (with a 300 to 400-year reserve in the ground), it is not good national energy policy to adopt major legislation that will cause our nation to turn its back on it's most abundant energy resource in favor of a fuel that is much more limited in supply and which historically has been subject to volatile price fluctuations.

While the high and the low sulfur coal interests have been jockeying for advantage with respect to this legislation, they have failed to see the "big picture", i.e., that this legislation will, even in the near-term, prove to be disastrous for the coal industry as a whole. As an illustration, AEP in its various approaches to compliance is giving very serious consideration to switching not to low sulfur coal, but to natural gas, at a number of its older, smaller units.

THE BUSH ADMINISTRATION'S CLEAN-AIR PLAN IS TAILORED TO GAS USE, Environmental Protection Agency Assistant Administrator William Rosenberg told the Natural Gas Roundtable last week. At the group's monthly luncheon in Washington, Rosenberg maintained that "I don't think we could have written it any stronger for your industry, and we did it very intentionally." He called the administration's proposed amendments to the Clean Air Act a "clean-fuels bill, and very appropriately a pro-gas bill."

Because gas is domestically produced and is a clean and economic fuel, "there really is no reason why public policy should not promote it," Rosenberg asserted. "In fact, there is every possible reason why, from an energy point of view, from an environmental point of view and an economic point of view, public policy should make it easier to use gas."

Acknowledging the gas industry's concern about the possibility of the adoption of cost-sharing provisions to finance the cleanup, like a tax on electricity production (*IF*, 18 Sept, 11), Rosenberg sought to allay that fear. He reported that a Nov. 3 letter from White House Chief of Staff John Sununu to Rep. Henry Waxman, D-Calif., set out "in the strongest terms that I have seen out of the White House" the administration's flat opposition to any cost sharing through a fee or a tax. "We share your trepidation," Rosenberg told the industry officials, but "we don't think the votes are there to secure cost sharing and the administration could not be clearer in its position."

QUESTION FROM SENATOR McCLURE

Q.4. Isn't it true that the SO_2 and NO_x caps will have a disproportionate negative impact on western states, as they do not have the resource of allowances, as prescribed by this bill, as compared to the east [sic]?

A. The $\underline{SO_2}$ cap will create a somewhat more severe problem for the western states (and Florida) than for other states. Although S. 1630 does provide low-emitting plants with allowances, it is much more difficult and costly to overcontrol low emitting sources in order to create allowances that could be used to support future growth. In this sense, the western states (and Florida) are faced with a more difficult problem than the rest of the country. However, it is only a matter of degree for, as a result of the SO_2 reductions mandated by Phase II, even the higher emitting states of the Midwest and the Southeast will become low-emitting states. For example, as a result of Phase II compliance, the average SO_2 emission rate for coal-fired power plants on the American Electric Power System is expected to be about 0.85 lbs. per million Btu under S. 1630 -- making further reductions for overcontrol purposes very difficult and expensive. If, as noted later herein, we were to shelter those of our plants which have wet-bottom boilers from the NO_x requirement of S. 1630 by utilizing the 1.5 tons of SO_2 for 1.0 lbs of NO_x trading mechanism, our AEP system-wide SO_2 emissions rate would be reduced from 0.85 lbs. to 0.79 lbs. -- making additional SO_2 reductions even more difficult and costly and putting us in the same league as the "low emitting" states of the West. As I tried to emphasize in my testimony before your Committee, this problem of inhibiting economic growth is inherent in the SO_2 cap.

The impact of the NO_x cap is somewhat different, however. Powerplant NO_x emissions are distributed in a rather random fashion throughout the nation, i.e., there are no "low-emitting", "clean" or "dirty" regions of the country insofar as NO_x emissions are concerned. In this general sense, the NO_x cap should not hurt one region more than another. However, differential regional impacts may nevertheless result from S. 1630's NO_x requirements. For example, there is a high concentration in the Midwest (Ohio, Indiana, Illinois) of power plants which, because of boiler design and configuration, cannot be retrofitted with low NO_x burners. For these plants, there presently appears three alternatives: (i) retrofit with selective catalytic reduction (SCR), which is an expensive technology that has not yet been demonstrated on plants such as those in the Midwest which burn higher sulfur coals; (ii) premature retirement in 2000; or (iii) further SO_2 overcontrol utilizing the SO_2-NO_x trading mechanism of S. 1630 to shelter such units. Because of this boiler design problem, the Midwest will be hit the hardest by the NO_x cap. However, to the extent that alternative (iii) is utilized by midwestern utilities to protect their wet-bottom boiler plants, there will be even fewer SO_2 allowances available in the Midwest for sale to the West. Thus the problem posed by the wet-bottom boilers of the Midwest could, by indirection, have a negative impact on other regions of the country. Insofar as regional impacts are concerned, it should also be noted that, under S. 1630, the NO_x emissions cap and concomitant 100% NO_x offset requirement are applicable only to coal-fired units. Thus, coal-burning regions of the nation will be impacted by the NO_x cap to a greater extent than regions which rely to a greater extent on other fuels. These problems, of course, would be solved by reverting to the NO_x provisions of H.R. 3030.

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Executive Director
Ben Yamagata

Responses of Ben Yamagata
Executive Director, Clean Coal Technology Coalition

to

Written Questions
January 24 and 25 Energy Committee Hearing

Questions posed by Senator Ford:

1. As an incentive, S. 1630 extends the compliance date for Phase II (2000) sulfur dioxide requirements for existing units which propose to meet those requirements by repowering with clean coal technologies (cct). By limiting, however, the compliance date extension to units which "repower" with clean coal technology, the bill fails to recognize sulfur reduction technologies that do not involve repowering which DOE is supporting thought the CCT program. Is this limitation justified in your opinion?

How much money is being spent by DOE on these excluded clean coal technologies?

Answer: Limiting the Phase II deadline extension to repowering clean coal technologies (as defined in S. 1630) may slow or halt the development of a number of promising, retrofit technologies that may not be adequately proven in time for consideration as a compliance method in meeting the Phase II compliance deadline. Retrofit technologies, which are technologies used on an existing plant to reduce emissions, may be more promising as near term (before 2005) methods of compliance than several of the repowering technologies signaled out in S. 1630 for a compliance deadline extension.

Retrofit technologies are important alternatives for control of SO2 and/or NOx because they generally offer a means of reducing emissions by 40 to 90 percent, at costs significantly less than installing conventional scrubbers or SCR (NOx control) technology. Several of these technologies are capable of simultaneously reducing SO2 and NOx emissions and thus, retrofit technologies can help to moderate rate impacts on the electric consumer since they generally have lower capital and operating costs.

The private sector and the federal government, through the DOE clean coal program, have already invested significant amounts of money in the development of retrofit technologies. Indeed, of the nearly $3 billion investment represented by the 39 projects that have been selected by DOE under the first three rounds of the program, 25 projects can be classified as pre- or post-combustion retrofit technologies. S. 1630, in denying the time extension for retrofit technologies, risks wasting this significant private sector and federal investment in the development of these important technologies.

2. Mr. Yamagata, if the Senator were to restore those clean coal provisions contained in the President's clean air proposal but not included in S. 1630, and were to adopt the amendments advocated by your group, can you give me an assessment of the impact this would have on the utility industry's ability to use clean coal technologies in complying with the emission reduction requirements of the legislation?

Providing regulatory incentives, additional time, and more flexibility to use a clean coal technology for compliance, as would be provided by the amendments advocated by the Coalition, and including those clean coal incentives recommended in the President's proposal but not included in S. 1630 as reported, will encourage utilities to utilize these technologies in order to comply with the reduction requirements of S. 1630. Without such provisions, it is unlikely that the utility industry will aggressively develop clean coal technologies, in which case they will not be available for use in compliance with emission reduction requirements.

The Electric Power Research Institute (EPRI) recently released an evaluation of two alternative SO2 emissions control strategies: one based on the President's proposed acid rain abatement program, and the other based on the rapid deployment of new clean coal technologies in new and repowered utility power plants. I submit that evaluation as part of the answer to this question.

As you will note in the evaluation, EPRI asserts that the clean coal alternative offers lower CO2 emissions, significantly reduced solid wastes, higher energy efficiency at a much lower cost than a control proposal. Therefore, the Coalition believes that even if a control proposal, like the one proposed by President Bush, is ultimately approved by the Congress, that proposal should make available every incentive feasible to encourage the use of these less costly and environmentally superior technologies.

Question Posed by Senator Heflin:

You have stated that it is important for the Senate to restore the President's provision that alleviates the burden of the so-called EPA "WEPCo" decision for clean coal technology projects. I understand that EPA has formally responded to the Northern Indiana Public Service Company (NIPSCO), favorably exempting their clean coal project from a WEPCo-like review. Can you explain the impact that the WEPCo decision has had on the development of clean coal technologies and what further impact it is likely to have if Congress does not provide some statutory relief?

The so-called "WEPCo" decision has had a chilling effect on the utility industry's participation in the clean coal program. Several utilities, selected for participation in the DOE clean coal program, have indicated an unwillingness, to proceed with a clean coal project unless and until it is clearly determined that the WEPCo decision would not apply. The problem is that utilities that undertake demonstrations of promising clean coal technologies may, by reason of the demonstration, expose itself to stringent environmental requirements

1) if the technology does not ultimately reach anticipated levels of emissions control;

2) is removed after the demonstration is completed; or

3) does not achieve the same emissions reductions as conventional - but more expensive - control technology.

In each case, the utility could be confronted with application of stringent environmental standards on a particular unit for having undertaken the voluntary action of demonstrating or utilizing a new clean coal technology. If the clean coal demonstration were not conducted, such exposure to greater environmental regulation would be avoided. The reality is that few, if any, utilities are prepared to take such a risk.

The EPA letter to NIPSCO, under date of January 5, 1990, states the EPA will issue an "interpretive ruling" that will clarify that a source that "solely adds or enhances systems or devices whose primary function is the reduction of air pollution and that are determined to be environmentally beneficial" would not trigger NSPS and/or PSD and nonattainment new source review. EPA further clarifies that the ruling would apply to both temporary and permanent clean coal projects; but that it would not extend to projects that "primarily extend the life of a plant or increase capacity" (which may mean that the exemption would not be available to all of the clean coal program projects that demonstrate repowering technologies such as PFBC and IGCC).

Such an interpretive ruling by EPA, as promised in communications with NIPSCO, if it is finally issued, could relieve much of the uncertainty currently facing a utility that is considering participation in the clean coal program. Since EPA has yet acted, we would urge that the Senate restore the provisions of the Bush clean air proposal that provide clean coal projects with some relief from the burden of the WEPCo decision.

Question posed by Senator Ford:

What impact will the compliance dates in the legislation have upon the clean coal technology program?

Answer: The compliance deadlines in S. 1630 may impede a utility's ability to use clean coal technologies because many of these technologies will not be available and commercially proven in time to plan for and then to meet the deadlines - January 1, 1995 for Phase I and January 1, 2000 for Phase II. The technologies must be commercially available for confident use several years (4 to 6) in advance of the compliance deadlines to allow for design, permitting, construction and initial testing/shake down.

I have attached a chart giving the Coalition's estimate of the expected commercial availability of the suite of clean coal technologies. The availability dates of several important technologies demonstrates that few, if any, of the technologies would be available for confident use in meeting the proposed Phase I deadline and, keeping in mind the time needed to plan for use of new technologies, several will require time beyond even 2003 in order to be a candidate for use in meeting an extended Phase II deadline. In addition, these dates do not factor in the disincentives to demonstrating new technologies that may occur should industry be required to plan and execute programs to meet reduction requirements at the same time these technologies are being developed.

The Coalition believes that clean coal technologies, given current levels of development and associated risks, will be a very limited option for meeting reduction requirements unless adequate time and flexibility in compliance are provided in Clean Air Act legislation that may be enacted by the Congress. Unless opportunities for use of these technologies are provided, it is possible that the on-going clean coal program, to which Congress has appropriated more than $2.5 billion -- and to which the private sector will contribute more than $2.5 billion, will be jeopardized.

Questions posed by Senator McClure:

1. The Clean Coal Coalition has recommended that the extension in the Phase II compliance deadline for certain clean coal technologies, which is currently set at December 31, 2003,

should be extended until the year 2005. Can you please explain why a five year, rather than a three year extension is warranted? What benefits would be realized through such an extension, and do such benefits justify the possibility of greater emissions for an additional two years?

Answer: The development, demonstration and subsequent widespread deployment of new technology takes time. The utility industry needs enough time to acquire adequate engineering data so that industry and utility regulatory commissions will have confidence that the technology will meet commercial needs. Such data can only be obtained through the replication of successfully demonstrated technologies in a limited number of commercial applications and by giving industry a sufficient amount of time during which to gain that confidence.

Under S. 1630, industry will have to make a decision on a means for compliance before many clean coal technologies are projected to be available for confident commercial use by the utility industry - even if a three year extension in the Phase II deadline is provided. An extension, until the year 2005, would give industry more time to acquire data and experience with the technologies, thereby increasing the likelihood that a) the technologies will be available for widespread commercial use and b) that a utility could count on the technology to be a reliable, cost-effective means of achieving the required reductions.

2. S. 1630 does not contain compliance date extensions for clean coal technologies as in the Administration's proposal.

a. Does the panel support the addition of such a provision to the bill?

b. What should be the criteria used to establish eligibility for such compliance date extension?

Answer: S. 1630 provides a four-year extension for use of clean coal technologies, but the deadline for compliance when utilizing a technology is the same as the President's proposal (December 31, 2003).

The Coalition believes that the entire suite of clean coal technologies should be made eligible for the compliance deadline extension.

3. The Administration's bill is limited to repowering technologies.

a. What other types of clean coal technologies are currently being funded by the Administration?

b. Should these other technologies be eligible for such compliance date extensions? If not, why not?

Answer:

Limiting the Phase II deadline extension to repowering clean coal technologies (as defined in S. 1630) may slow or halt the development of a number of promising, retrofit technologies that may not be adequately proven in time for consideration as a compliance method in meeting the Phase II compliance deadline. Retrofit technologies, which are technologies used on an existing plant to reduce emissions, may be more promising as near term (before 2005) methods of compliance than several of the repowering technologies signaled out in S. 1630 for a compliance deadline extension.

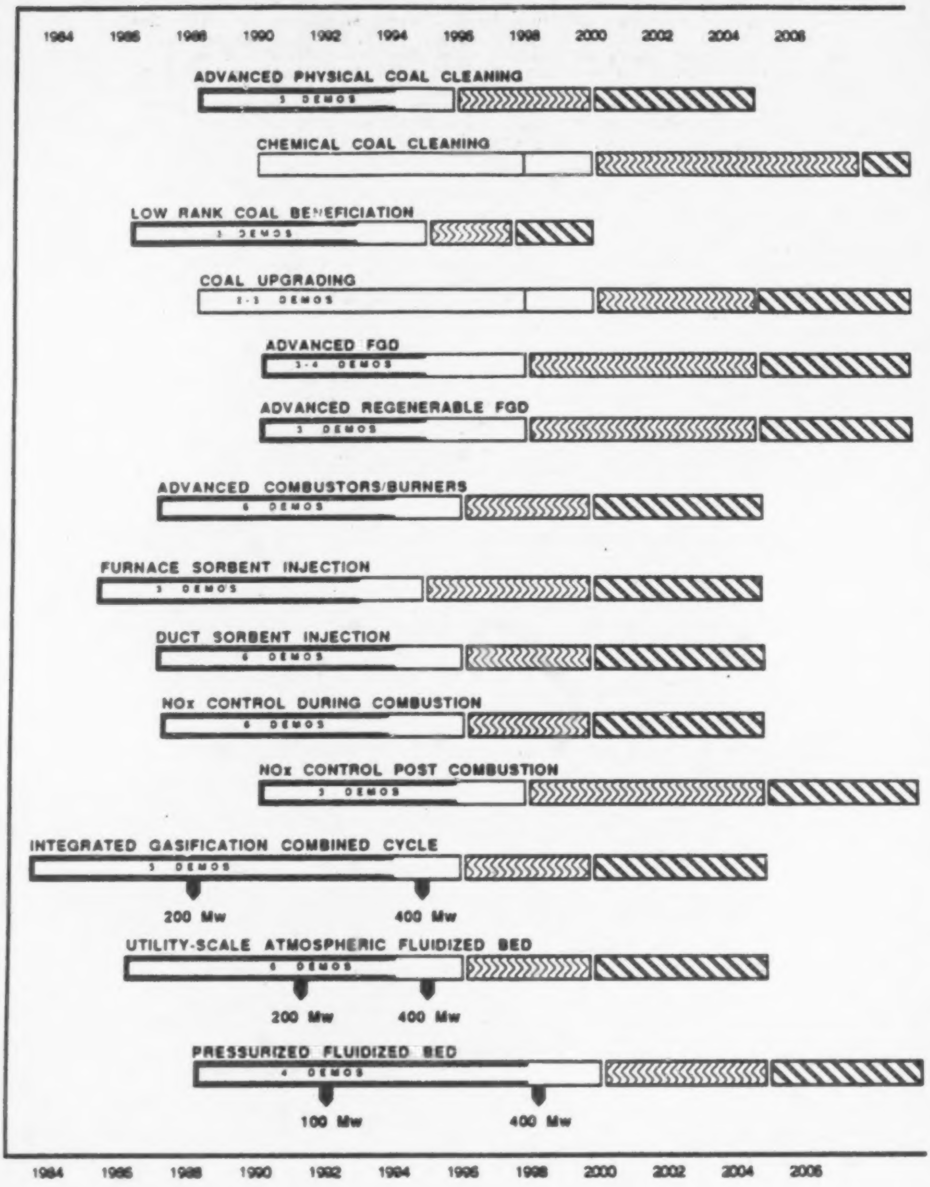
Retrofit technologies are important alternatives for control of SO2 and/or NOx because they generally offer a means of reducing emissions by 40 to 90 percent, at costs significantly less than installing conventional scrubbers or SCR (NOx control) technology. Several of these technologies are capable of simultaneously reducing SO2 and NOx emissions and thus, retrofit technologies can help to moderate rate impacts on the electric consumer since they generally have lower capital and operating costs.

4. As an incentive, S. 1630 extends the compliance date for Phase II (2000) sulfur dioxide requirements for existing units which propose to meet those requirements by repowering with clean coal technologies (cct). By limiting, however, the compliance date extension to units which "repower" with clean coal technology, the bill fails to recognize sulfur reduction technologies that do not involve repowering which DOE is supporting thought the CCT program. Is this limitation justified in your opinion? How much money is being spent by DOE on these excluded clean coal technologies?

Answer:

The private sector and the federal government, through the DOE clean coal program, have already invested significant amounts of money in the development of retrofit technologies. Indeed, of the nearly $3 billion investment represented by the 39 projects that have been selected by DOE under the first three rounds of the program, 25 projects can be classified as pre- or post-combustion retrofit technologies. S. 1630, in denying the time extension for retrofit technologies, risks wasting this significant private sector and federal investment in the development of these important technologies.

CLEAN COAL TECHNOLOGY AVAILABILITY



LEGEND:

▭ Demonstration & Deployment Projects Undertaken and Completed

☐ Estimated period after demo/deployment projects when Technologies likely to become available for Commercial Order

▒ Period of time during which technologies could begin to enter the marketplace as commercial units

▨ Period of time when technology could achieve potential widespread commercial use to achieve reductions of air pollutants

Clean Coal Technology Coalition September, 1989

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CHRIS FARRAND
Vice President
Government Relations

January 31, 1990

Honorable J. Bennett Johnston
Chairman, Committee on Energy and
  Natural Resources
United State Senate
Washington, D. C. 20510-6150

Attention: Patricia Beneke

Dear Mr. Chairman:

Enclosed herewith are the responses to the specific questions posed to us after the January 24, 1990, hearing on S. 1630, the proposed Clean Air Act amendments and acid rain controls.

I am grateful for having had the opportunity to appear before your Committee. I believe the structure of the hearings, especially the organization of the three panels of witnesses, was conducive to an effective dialogue on the very complicated provisions of the legislation. You and your staff are to be congratulated for the contribution you have made to the better understanding of the bill at a critical time in the Senate's debate.

Sincerely,

Chris Farrand

Enclosure

CF:mm

Responses to Questions
Senate Energy and Natural Resources Committee
Hearings on Acid Rain Legislation
January 24, 1990

Coal Market Impacts

(1) DOE has stated that in the year 2000 about 100-200 million tons of coal production would shift from high sulfur regions to low sulfur regions due to proposed acid rain legislation.

- Do you agree with this estimate?

RESPONSE:

We believe the estimate of 100-200 million annual tons displaced is too high. Peabody's estimate is that approximately 60 million tons will be displaced as a direct result of proposed acid rain legislation. Our range of estimates would be from 50-100 million tons displaced.

We would strongly caution, however, that all of these estimates, including DOE's and our own, are extremely sensitive to the assumptions used about scrubber costs and the prospective prices of low-sulfur coal delivered to the affected powerplants. Other factors include the applicability of clean coal technology and the physical receptivity of individual powerplants to retrofit or repowering technologies, both conventional and advanced. Also, the possible application of hazardous air pollutant controls on powerplants could influence decisions about scrubbers, which in turn would affect the amount of fuel switching which might occur.

(2) DOE has estimated that the President's bill will increase the cost of producing electricity from coal by about 5-8 percent.

- Do you agree with this estimate?

RESPONSE:

Peabody would concur with this estimate as a nationwide average, but our information would indicate that electricity rate increases in some regions and from some utilities may be substantially higher, e.g. 20-30 percent. If utilities must also comply with rigid hazardous air pollutant controls requiring maximum available control technology (MACT), the average increase would be higher than the DOE estimate or our own estimates.

Clean Coal Technologies

(1) The Clean Coal Coalition has recommended that the extension in the Phase II compliance deadline for certain clean coal technologies, which is currently set at December 31, 2003, should be extended until the year 2005. Can you please explain why a five-year, rather than a three-year extension is warranted? What benefits would be realized through such an extension, and do such benefits justify the possibility of greater emissions for an additional two years?

RESPONSE:

Under the proposed legislation, utilities must "declare" their intention to apply clean coal repowering technology by 1998, before both DOE and many utilities feel these technologies will be sufficiently mature for wide-spread application. An extension of the deadline until 2005 presumably would extend the deadline for declaring one's intention and provide more time for more utilities to become confident in these technologies.

Also, the extra time may permit commercial development of a wider range of technologies or the application of technologies on a larger scale. Both of these possibilities will have a bearing on the ultimate reliability and cost of controls with which electricity will be produced from coal.

It is impossible to predict at this time how many utilities will opt for application of clean coal technology and thereby be granted an extension to the Phase II deadline. However, we believe that any additional emissions resulting from the extra extension for certain powerplants will be offset by three factors: (a) lower ultimate emissions rates (i.e., lower cumulative emissions) than may be achieved by conventional technologies; (b) the possibility that emissions of NO_x and other pollutants, including CO_2, may be reduced from the application of advanced technologies, and (c) the emission reductions may be achieved on a more cost effective basis.

We believe these benefits justify the extension of the deadline until 2005.

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Charles H. Goodman
Vice President

the southern electric system

May 18, 1990

Ms. Wanda Freeman
c/o Senate Committee on Energy
  and Natural Resources
Room 364, Dirkson Building
Washington, D.C. 20510

Dear Ms. Freeman:

Enclosed are responses to questions raised at the January 24-25, 1990 hearings on Energy Policy Implications of S1630.

Please call if you wish more information.

Sincerely,

Charles H Goodman

Charles H. Goodman

sll:3821

Enclosure

cc: Southern Company Services
    Mr. J. E. Neumann

Response By Dr. Charles H. Goodman to Questions From the Senate Energy and Natural Resources Committee

Question No. 1

It would seem that this dramatic decline in SO_2 emissions occurred from largely unregulated emissions. I don't think we can expect to keep reducing forever or even keep reducing it economically. We have already taken out the cheap tons. I also hear that low emitting states will be looking for allowances if they want to burn coal. Not it seems to me that the scramble for allowances and the perpetual [SO_2] cap will drive this nation away from coal. Do you agree?

Answer

Yes, we agree that the SO_2 cap will make it extremely difficult, if not impossible, for the nation to utilize its most available energy resource: coal. States that have relatively low emissions today will be looking for allowances to provide for growth tomorrow. Many of these states are where high economic growth is occurring and it is a fact that growth requires energy. Other states, through overcontrol, may have more allowances than immediately needed but be hesitant to transfer them so as to allow for economic growth at home. State PSC's may exacerbate this self protective attitude. Growth and its resultant energy requirements will be increasingly expensive and could eventually make it virtually impossible to use any fuel that contains sulfur, including coal.

Question No. 2

Do you agree that at some point, the use of any sulfur fuel would be impossible?

Answer

As noted above, that would be the ultimate effect of an SO_2 cap.

Question No. 3

If so, where will we get our energy for growth to support the economic expansion Mr. Rosenberg alleges [can still occur with the cap]?

Answer

Alternative, non-SO_2 emitting sources of energy would ultimately be required to support future economic growth or something akin to "pristine" technologies. These would include nuclear, gas (although gas may have problems with NO_x), hydro-electric and alternative sources (solar, etc.). However, we do not believe that these sources can provide the energy supplies necessary to allow for projected economic growth, even with forcing provisions and accelerated research.

Question No. 4

What would you recommend?

Answer

We believe that the best energy policy for America is one that relies on the efficient, clean use of all available domestic energy supplies. This would necessarily include coal. We believe that without the use of coal, our nation is committing itself to shortfalls of necessary energy supplies in the future.

Question No. 5

Mr. Rosenberg told us that the states doing the most clean up currently have lower rates and that nationally, we can expect about a 3% rate increase. He gave us the impression that these low-cost states could better afford rate increases. Do you agree with this philosophy and Mr. Rosenberg's figures?

Answer

No. To begin with, Mr. Rosenberg's estimates apparently include only the cost of the acid rain title and not the air toxics title about which I testified. In dealing with acid rain, Mr. Rosenberg uses an average electricity cost of 48 states to mask significant regional and state differences. An analysis of S. 1630 (including air toxics) by an independent economic consultant, Temple, Barker and Sloane, reveals that on a statewide average basis, 10 states would have rate increases in excess of 20% and an additional 16 states would experience rate increases of 10% to 20%. While averaging nationwide might mask these impacts, the residential and business customers of certain individual utilities will still be burdened with tremendous increases in their energy bills.

With regard to claims that states with lower energy costs can better afford to absorb cost increases, I strongly disagree for two reasons. First, the economy of these regions has developed based on their traditional energy costs and can be very sensitive to energy prices.

The second reason that I believe lower energy cost states are not better able to absorb cost increases is illustrated by the area we serve. Most of the southeast is still trying to catch up economically with the rest of the country. To say that these states are better able to afford higher energy costs is not only incorrect, it is probably exactly backward.

Question No. 6

[Question 6 was apparently intended for EPA.]

Question No. 7

I have read in testimony before the House Subcommittee on Health and [the] Environment that cofiring natural gas with coal gave encouraging emission reduction results at Duquesne's Cheswick Station.

a. Did those results cause you to consider natural gas cofiring in a favorable light?

Answer

We were very interested in the Cheswick test results but, to better understand the applicability to our system, we conducted our own coal/natural gas cofire test at Alabama Power's Plant Gadsden in September 1989 in conjunction with Sonat Inc. Using a very structured test procedure following ASTM standards, we found less emission reductions than in the Cheswick test. Long-term tests under a wider range of conditions will be necessary to fully understand the environmental potential of cofiring.

b. Is natural gas a part of your utilities compliance plan? If not, why not?

Answer

Year-round cofiring with natural gas has not been found to be economically attractive at Southern system plants in our preliminary computer simulations due to the projected rising cost of gas. Seasonal cofiring appears more promising and is being actively pursued.

The Committee should also be aware that a major barrier to the ability of any utility to employ natural gas or cofiring to reduce emissions may be EPA's current interpretations of the Act's new source regulations (the WEPCO decisions). New source requirements, according to the EPA, could be triggered even when a facility elects to switch to a cleaner fuel. Unless EPA returns to its earlier interpretations of the new source requirements, natural gas cofiring may be precluded, or, at a minimum, discouraged.

c. A few weeks ago I saw a short newspaper article about a cold snap along the Gulf Coast and something about natural gas. Could you elaborate on that?

Answer

Yes. A number of our generative plants located in the operating territories of Alabama, Georgia, Gulf, Mississippi and Savannah Power Companies use natural gas for boiler flame stabilization and as a base fuel in smaller units for peak generation needs. During the recent cold snap you referred to, our natural gas supplies were interrupted across our entire system and diverted for residential use. Both of the major interstate pipelines which supply our system notified our operating companies that as interruptible customers, we were to cease the use of natural gas until further notice. Two of our larger generating facilities are heavily dependent on natural gas for flame stabilization and continued to take natural gas after the notification inadvertently for a short time as we were fully engaged in exporting power to adjacent regions suffering from dramatic electricity shortages. The cost of that gas was four times our normal price.

d. Have you tried to negotiate for natural gas supplies recently?

Answer

Yes. We routinely purchase natural gas for boiler light-off, boiler flame stabilization and for peaking generation purposes. We have found gas prices to be priced competitively with other fuels during the summer but that gas commands a very large premium and carries a high risk of interruption during the winter months.

e. What is the approximate price differential you have been quoted for reliable gas supplies versus your current major fuel supplier?

Answer

The Southern electric system is the largest utility user of coal in the United States. Approximately 80% of this coal is supplied by long term contracts to assure our customers a reliable source of energy. The average cost of 44 million tons of coal to our system in 1989, was approximately $2.10 per MMBtu delivered. In 1989, we negotiated with natural gas suppliers for a firm (non-interruptible) supply of natural gas to one of our plants for $3.50 per MMBtu delivered.

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APPENDIX III

Additional Material Submitted for the Record

ATTACHMENT A

TESTIMONY OF
JAMES R. MAHONEY
DIRECTOR
NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

BEFORE THE
SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE

OCTOBER 5, 1989

Mr. Chairman and Members of the Subcommittee, I appreciate your invitation to appear before the Subcommittee today, to present testimony on the scientific and technological aspects of acidic deposition and its control. The National Acid Precipitation Assessment Program was created by Congress in 1980 (Public Law 96-294) to conduct scientific, technological, and economic analyses of acidic deposition causes and effects, and to evaluate the available approaches to its control. The statute assigns NAPAP the responsibility of reporting its assessment findings for use by the President, the Congress, and the public. To meet this responsibility NAPAP has (1) conducted its own research through its participating Federal Agencies and Departments, (2) analyzed other relevant technical studies conducted in the United States and in other nations, and (3) established an assessment framework to report complicated technical information in a manner useful to policy officials and the interested public.

My testimony today summarizes much of the current scientific information about acidic deposition effects, and describes key findings from some recently completed projections of future surface water chemistry at different deposition levels. NAPAP is preparing a broad set of projections to compare the range of control costs and environmental benefits associated with various levels, schedules and geographic patterns of emission controls. While many of these projections are not yet available, I want to give you the sense of my current scientific judgment. As a reference point for my comments, I note that you are considering several suggestions for SO_x emission reductions of ten million short tons below 1980 levels. In my view, emission reductions in this range would benefit aquatic resources and would mitigate other environmental effects caused by acidic deposition and its precursors as described in this testimony and other NAPAP reports. To preserve its credibility as technical fact finder, NAPAP does not make recommendations about specific control levels. We recognize that you in the Congress, together with the President and his policy officials, must make these decisions after considering the available scientific information and weighing many other concerns.

NAPAP has established guidelines to report two types of information in its assessment:

(1) The best technical conclusions supportable by evidence. NAPAP's comprehensive assessment reports are being subjected to intensive scientific peer review, interagency review, and open review by all interested members of the scientific community and the public, to assure soundness and objectivity in the reported findings.

(2) Descriptions of the confidence level associated with each conclusion. Given the complex task of isolating the environmental effects of acidic deposition from other sources of variability, such as natural stresses and various anthropogenic factors, a degree of scientific uncertainty is unavoidable. NAPAP's technical findings are being coupled with explicit statements of confidence levels to aid decision-makers in using the information.

NAPAP's assessment reports, scheduled for completion at various dates between December 1989 and September 1990, are currently in preparation and review. NAPAP will provide each of these reports to the Congress as soon as it is available.

The remainder of my testimony is divided into three parts. First, NAPAP's current information on acidic deposition effects and the status of control technologies is summarized, as background for your consideration of proposed legislation. The second part notes some of NAPAP's key accomplishments, to document how the research and assessment program has greatly improved our understanding of acidic deposition. The final part responds to your question about the potential use of continued data collection after NAPAP's mandate expires in 1990.

PART 1 - SUMMARY OF SCIENTIFIC INFORMATION

Sources of Acidic Deposition

The chemical precursors involved in producing acidic deposition are sulfur dioxide, nitrogen oxides, and volatile organic compounds. Sulfur dioxide and nitrogen oxides are produced in the combustion of fossil fuels. Volatile organic compounds are emitted from many industrial, transportation, and natural sources; these compounds, acting together with the nitrogen oxides, produce oxidants involved in the conversion of sulfur and nitrogen oxides into acidic compounds.

NAPAP has developed a comprehensive inventory of anthropogenic emissions for the United States and Canada for the base years 1980 and 1985. Estimated anthropogenic emissions for the United States for 1985 are:

- 23 million short tons of sulfur dioxide (70% from electric utilities),
- 21 million short tons of nitrogen oxides (40% from transportation sources, 33% from electric utilities), and
- 22 million short tons of volatile organic compounds (40% from transportation sources, much of the rest from solvent evaporation).

NAPAP has also estimated annual emissions trends through 1987, with preliminary estimates for sulfur dioxide and nitrogen oxides for 1988. Between 1973, the peak year of sulfur dioxide emissions, and 1988, sulfur dioxide emissions in the United States decreased by 23% from approximately 31 to 24 million short tons, despite a 45% increase in coal use. The decrease resulted from increased use of low sulfur coal and flue gas desulfurization (scrubbers), increased nuclear power production and decreased utilization of some higher emitting power plants and industrial sources. Most of the reduction was achieved by 1982; during the last six years sulfur dioxide emissions have remained relatively constant.

Emissions of nitrogen oxides peaked in 1978 at 23 million short tons and have since declined. Preliminary estimates of 1988 emissions are 20 million short tons, which is a 14% decrease from 1978. Emissions of volatile organic compounds have also decreased during the last ten years; preliminary estimates for 1988 are 21 million short tons, which is a 28% decrease since 1978.

Natural sources of sulfur emissions in the United States are minor by comparison to anthropogenic sources. Natural sources of nitrogen oxides are also estimated to be small, but in some areas important, in the United States compared to anthropogenic sources. Although less certain, regional estimates of volatile organic compounds emissions from natural sources are approximately as large as anthropogenic sources.

Future levels of anthropogenic emissions will be determined by many factors in addition to implementation of emission controls. Among the most important for sulfur dioxide are regional patterns of population growth, future energy demand and the rate of retirement or repowering of older, higher emitting power plants.

Effects of Acidic Deposition

The six principal categories of acidic deposition effects to be included in NAPAP's final Assessment are: aquatic ecosystems, forests, crops, exposed materials, human health, and visibility in the atmosphere. My statement today covers the first four of these categories, for which NAPAP has sponsored extensive research. Because acidic deposition emission precursors may also affect health and visibility, NAPAP also monitors and evaluates research activities in these areas and will report on these areas in its Integrated Assessment. Each of the effects categories addressed considers two key questions: (1) what damage can be attributed to current levels of acidic deposition?; and (2) what benefits (i.e., reduction in physical and/or economic damages) would be expected to result from reduced levels of acidic deposition?

Effects on Aquatic Ecosystems

The potential acidification of aquatic systems resulting from acidic deposition has been a driving influence in research and control activities in Europe (especially the Scandinavian countries), in Canada and the United States, and more recently in other nations. It is widely acknowledged that some watersheds, lakes, and streams have been acidified as a result of acidic deposition and that others have adequate buffering as a result of geological and soil conditions, so that they are not subject to significant effects from acidic deposition. Therefore the concern about aquatic effects is focused on those regions or watersheds which have relatively low buffering capacity. These sensitive regions have been mapped in detail by NAPAP for the United States and by Canadian governmental organizations for Canadian resources.

My testimony presents quantitative information about current chemical status and future projections for lakes and streams in sensitive regions, based on NAPAP-sponsored research. The quantitative information is summarized in the following seven questions and responses.

Question 1: Are there acidic lakes or streams in the United States?

Yes. Surveys conducted by NAPAP describe the numbers of chronically acidic and sensitive lakes and streams in the different regions studied in the National Surface Water Survey. These regions are identified in

Figure 1 and the percentages of acidic[1] and sensitive[1] systems are summarized in Tables 1 through 3.

Question 2: How many of these acidic lakes and streams result from acidic deposition?

In the Northeast and the Southeast outside of Florida, I believe most of the acidity in acidic and sensitive surface waters comes from acidic deposition. Lake sediment cores also provide independent information suggesting acidification due to acidic deposition. In other regions, such as Florida and the upper Midwest, the contribution of acidic deposition to total acidity is smaller.

Question 3: Could this situation become worse?

Yes. With deposition continuing at current levels, streams could acidify in the Southern Blue Ridge Region where now none are acidic. Although the results are not yet complete, projections indicate that more acidic streams are possible in the mid-Appalachian region as well. In the Northeast, minimal changes are projected to occur at current levels of deposition according to best estimates from model projections.

Question 4: Will reductions in emissions help?

Yes. According to our model projections, reductions in deposition would result in improved water quality in acidic lakes and streams in the Northeast and could limit or prevent deterioration in the Southern Blue Ridge Region. I expect our projections will show that reducing deposition will result in fewer acidic lakes and streams in the mid-Appalachian region as well. These results will be complete next spring.

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[1] Acidic waters are defined as those having acid neutralizing capacity (ANC) less than zero. Sensitive waters are defined as those having ANC above zero but less than 50 μeq/L.

FIGURE 1

NAPAP

Regions of the National Surface Water Survey

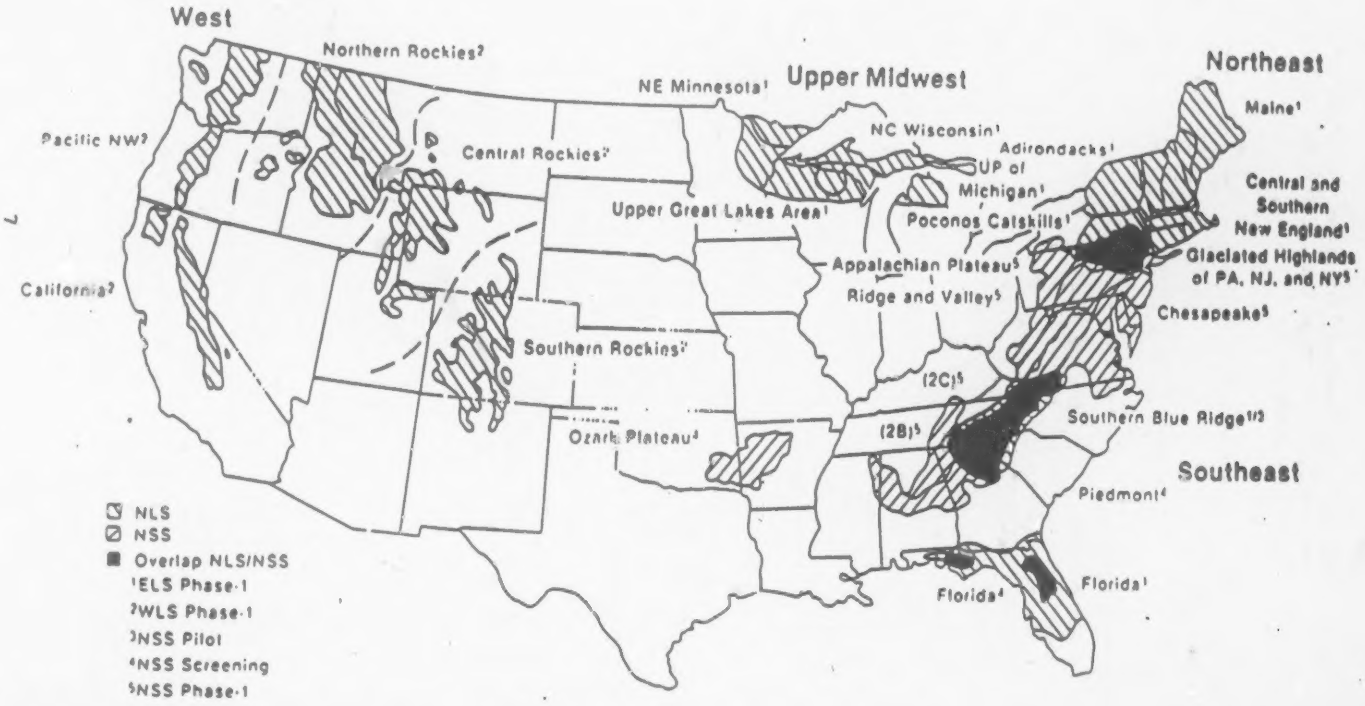
West
Northern Rockies²
Pacific NW²
Central Rockies²
California²
Southern Rockies²
NE Minnesota¹
Upper Midwest
Upper Great Lakes Area¹
NC Wisconsin¹
UP of Michigan¹
Adirondacks¹
Poconos Catskills¹
Appalachian Plateau⁵
Ridge and Valley⁵
Ozark Plateau⁴
(2C)⁵
(2B)⁵
Northeast
Maine¹
Central and Southern New England¹
Glaciated Highlands of PA, NJ, and NY⁵
Chesapeake⁵
Southern Blue Ridge¹/³
Southeast
Piedmont⁴
Florida¹
Florida⁴
▧ NLS
▨ NSS
■ Overlap NLS/NSS
¹ELS Phase-1
²WLS Phase-1
³NSS Pilot
⁴NSS Screening
⁵NSS Phase-1

Table 1. Estimated percentages[1] of target lakes[2] relative to selected reference values of pH and ANC for the regions and subregions of the lake surveys-Phase 1.

Subregion[3] and Regions[3]	pH			ANC (μeq/L)			
	≤5.0	5.0 to 5.5	≤6.0	≤0	≤50	≤100	≤200
1A Adirondacks	10	10	27	11	36	47	71
1B Catskills/Poconos	1	5	8	5	13	19	39
1C Central New Eng.	2	6	13	2	18	44	68
1D Southern New Eng.	5	5	15	5	22	32	67
1E Maine	1	1	5	1	11	34	67
1 Northeast	3	5	13	5	19	35	60
2A NE Minnesota	0	0	1	0	4	21	57
2B Upper Pen. of MI	9	4	18	10	19	29	42
2C No. Central WI	2	9	28	3	41	50	57
2D Upper Great Lakes	0	0[4]	4	0	10	18	31
2 Upper Midwest	2	2	10	2	15	26	41
3A So. Blue Ridge	0	0	0[4]	0	1	11	34
3B Florida	12	8	33	22	35	51	55
4A Sierra Nevada	0	0	1	0	37	70	87
4B Cascades/Olympics	0	0	2	0	20	40	72
4C No. Rockies	0	0	0	0	13	34	51
4D Central Rockies	1	1	1	0[4]	7	46	78
4E So. Rockies	0	0	0	0	5	18	39
4 Mountainous West	0[4]	0[4]	1	0[4]	17	43	67

[1] Percentages expressed in the table are based on numbers of lakes. Percentages based on lake area are usually less than the percentages by lake number. For example, in the Adirondacks the areal percentages for pH <5, 5 to 5.5 and <6 are 2%, 6% and 10% respectively. Complete information is available in the National Surface Water Survey Reports.

[2] Lakes greater than 4 hectares (ha) and less than 2000 ha for regions 1, 2 and 3; greater than 1 ha and less than 2000 ha for region 4.

[3] See Figure 1 for map of regions and subregions.

[4] Greater than 0.0 but less than 0.5.

Table 2. **Population Estimates of the Combined Length (km) and Percentage of Target Stream Reaches[1] with Spring Baseflow pH Less than Reference Values.**

	$pH \leq 5.0$		$pH \leq 5.5$		$pH \leq 6.0$		Total Length
Subregion	Length	%	Length	%	Length	%	(km)
Poconos/Catskills	550	3.6	906	6.0	1,354	8.9	15,144
N. Appalachians	1,424	6.6	1,870	8.6	3,044	14.0	21,738
Valley & Ridge	257	0.8	1,937	5.9	4,116	12.6	32,687
MA Coastal Plain	3,147	7.8	9,565	23.7	18,707	46.4	40,296
S. Blue Ridge	*	*	*	*	*	*	9,036
Piedmont	*	*	*	*	2,390	7.1	33,531
S. Appalachians	*	*	313	1.4	920	4.2	21,892
Ozarks/Ouachitas	*	*	410	1.8	2,437	10.8	22,480
Florida	522	13.6	1,708	44.4	2,828	73.5	3,848
SUBTOTALS							
Region							
Mid-Atlantic (MA)	5,378	4.9	14,277	13.0	27,221	24.8	109,865
Interior MA	2,231	3.2	4,712	6.8	8,514	12.2	69,569
Southeast (SE)	522	0.6	2,431	2.7	8,576	9.5	90,787
Interior SE	*	*	723	0.83	5,747	6.6	86,939
Total NSS-I	5,900	2.9	16,708	8.3	35,797	17.8	200,652

* No samples observed below this reference value; estimated percentage is less than 1%.

[1] The target population is estimated as 57,000 stream reaches with a combined length of 200,000 km. Target stream reaches may be described as small to mid-size streams with drainage areas of approximately 0.2 km^2 at the upstream end. Streams typically have widths of 1 to 6 meters and are between 0.1 to 0.5 meters deep. Complete information is available in the National Surface Water Survey Reports.

Table 3. Population Estimates of the Combined Length (km) and Percentage of Target Stream Reaches[1] with Spring Baseflow ANC Less than Reference Values.

	ANC ≤ 0		ANC ≤ 50		ANC ≤ 200		Total Length
Subregion	Length	%	Length	%	Length	%	(km)
Poconos/Catskills	543	3.6	1,606	10.6	5,489	36.2	15,144
N. Appalachians	1,524	7.0	3,713	17.1	12,935	59.5	21,738
Valley & Ridge	257	0.8	2,111	6.5	12,811	39.2	32,687
MA Coastal Plain	2,527	6.3	9,636	23.9	21,091	52.3	40,296
S. Blue Ridge	*	*	706	7.8	7,084	78.4	9,036
Piedmont	*	*	2,390	7.1	13,554	40.4	33,531
S. Appalachians	117	0.5	763	3.5	6,130	28.0	21,892
Ozarks/Ouachitas	*	*	205	0.9	15,092	67.1	22,480
Florida	461	12.0	2,356	61.2	2,939	76.4	3,848
SUBTOTALS							
Region							
Mid-Atlantic (MA)	4,851	4.4	17,067	15.5	52,327	47.6	109,865
Interior MA	2,324	3.3	7,431	10.7	31,235	44.9	69,569
Southeast (SE)	578	0.6	6,420	7.1	44,799	49.3	90,787
Interior SE	117	0.1	4,064	4.7	41,860	48.1	86,939
Total NSS-I	5,429	2.7	23,487	11.7	97,125	48.4	200,652

* No samples observed below this reference value; estimated percentage is less than 1%.

[1] The target population is estimated as 57,000 stream reaches with a combined length of 200,000 km. Target stream reaches may be described as small to mid-size streams with drainage areas of approximately 0.2 km^2 at the upstream end. Streams typically have widths of 1 to 6 meters and are between 0.1 to 0.5 meters deep. Complete information is available in the National Surface Water Survey Reports.

Question 5: What is the extent of these improvements?

In the Northeast, the models project that a 30% reduction in deposition will result in approximately half of those lakes which are currently acidic becoming nonacidic[2]. More specific information concerning projections for the Northeast and Southern Blue Ridge Region and their associated uncertainties is found in Tables 4 and 5. We expect that alkalinity would increase in the Mid-Appalachian Region. However, we cannot at this time project the extent and timing of these improvements. Our best estimates will be included in the Final Assessment.

Question 6: How long will it take for improvements to occur?

Chemical responses in the Northeast will begin to occur within one decade after emissions are reduced. Chemical responses in the mid-Atlantic and Southern Blue Ridge Regions which have greater sulfur accumulation capacity, will take several decades.

Question 7: How sure are you of your answers?

We are very sure of the current status of acidic and sensitive lakes and streams. We are less certain regarding our projections of future conditions. For example, there are significant uncertainties about the role that watershed mineral processes, organic acids and nitrates may play in the acidification and recovery processes. Determining the precise percentage of acidic waters due wholly, or in part, to acidic deposition carries with it scientific and statistical uncertainties. At present, the extent and impact of acidic episodes such as spring snowmelt and severe summer storms are uncertain but may subject surface waters and aquatic biota to periodic acidic stress. Work is underway to compare aquatic model projections with field observations to evaluate our ability to make projections. Although trends are evident in these projections, the effects of increased, constant, and decreased

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[2] The estimate is 75 lakes projected to become nonacidic, calculated as 162 lakes currently acidic minus 87 lakes remaining acidic after 50 years. See Table 4 for data and discussion of uncertainty limits. The projections do not include small (<4 ha) lakes expected to behave simiarly to the lakes in the target population.

Table 4. Lakes in the NE Projected to have ANC Values <0 and <50 µeq/L for Constant and Decreased Sulfur Deposition[1,2].

Time from Present (yr)		Constant Deposition		Decreased Deposition	
		ANC <0	ANC <50	ANC <0	ANC <50
0	#[3]	162[4]	880[4]	162[4]	880[4]
	%	5	27	5	27
20	#	161 (245)	648 (319)	136 (230)	621 (313)
	%	5 (8)	20 (10)	4 (7)	19 (10)
50	#	186 (251)	648 (329)	87 (237)	586 (332)
	%	6 (8)	20 (10)	3 (7)	18 (10)

[1] Projections are based on 123 lake/watersheds (>4 ha) successfully calibrated by the Model of Acidification of Groundwater in Catchments (MAGIC).

[2] The constant deposition scenario was at current levels. The decreased deposition scenario was held at current levels for 10 years then decreased linearly for 15 years to a level 30% below current deposition and then held constant.

[3] # is the number of lakes; % is percent of the target population of 3,227 lakes; the numbers in parentheses indicate the 95 percent confidence estimates, e.g. 161 ± 245.

[4] Indicates estimate from the National Surface Water Survey (NSWS) Phase 1 sample for the same 123 lakes; target population = 3,227 lakes.

Table 5. Streams in the Southern Blue Ridge Region Projected to have ANC Values <0 and <50 µeq/L for Constant and Increased Sulfur Deposition[1,2].

Time from Present (yr)		Constant Deposition		Increased Deposition	
		ANC <0	ANC <50	ANC <0	ANC <50
0	#[3]	0[4]	3[4]	0[4]	3[4]
	%	0	0.2	0	0.2
20	#	0	187 (310)	0	187 (314)
	%	0	14 (23)	0	14 (24)
50	#	129 (295)	203 (333)	159 (291)	340 (359)
	%	10 (22)	15 (25)	12 (22)	26 (27)

[1] Projections are based on 30 stream/watersheds successfully calibrated by the Model of Acidification of Groundwater in Catchments (MAGIC).

[2] The constant deposition scenario was at current levels. The increased deposition scenario was held at current levels for 10 years then increased linearly for 15 years to a level 20% above the current level then held constant.

[3] # is the number of streams; % is percent of the target population of 1,323 stream reaches; the numbers in parentheses indicate the 95 percent confidence estimates, e.g. 187 ± 314.

[4] Indicates estimate from the National Surface Water Survey (NSWS) Pilot Stream Survey sample for the same 30 streams; target population = 1,323 stream reaches.

deposition are not always statistically significant[3]. The quantitative estimates given here provide our best estimates, based on over four years of data collection and intensive analysis.

Surface Water Survey Information

Since 1984, NAPAP has conducted extensive surveys of lakes and streams. Figure 1 indicates the areas studied in the National Surface Water Survey (NSWS). Although acidic and sensitive surface waters may occur outside the regions studied, the majority occur within these regions. The chemical status of the lakes and streams in these regions is summarized in Tables 1 to 3.

The percentage of eastern and midwestern lakes and streams that are acidic varies from region to region. Similarly, a further percentage of these lakes and streams are highly sensitive to acidification. Proportions of acidic and sensitive surface waters within defined subregions are considerably higher (e.g., Adirondacks with 11% acidic and 36% sensitive) or lower (e.g., Maine with 1% acidic and 11% sensitive) than the regional values reported in Tables 1 to 3. In addition, lakes less than 4 ha were not sampled in the Eastern Lake Survey. In some areas, for example the Adirondacks, the percentage of acidic small lakes (less than 4 ha) is likely to be greater than the percentage of large lakes. The Adirondack Lake Survey Corporation has developed useful data for the Adirondack region (including small lakes). The Adirondack Lake Survey Corporation data indicate that 27% of the Adirondack lakes are acidic. This will be fully reported in the NAPAP Integrated Assessment. While survey information cannot by itself be used to establish the cause of the chemical status of a water body, it provides an estimate of the current number of acidic and sensitive surface waters and serves as a reference point for future monitoring. Biological impacts are expected in acidic and some sensitive waters.

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[3] Refer to Tables 4 and 5 for more information on confidence intervals.

Projections of Change in Surface Water Status

Regarding future status of surface waters, indications are that the steady-state hypothesis is valid in the Northeast, i.e., taken as a region, watersheds exhibit an approximate balance between sulfur inputs and outputs. This suggests that, in such areas, changes in sulfur inputs will more directly influence surface water chemistry. In the Southern Blue Ridge Region, systems are not in balance and soils are still adsorbing sulfur[4]. The Mid-Atlantic Region appears to be intermediate in its current ability to retain sulfur (Figure 2). These conditions lead to the following conclusions concerning future changes.

In the Northeast, under constant deposition, little chemical change is expected because systems are at steady state. Under a 30% decrease in deposition, approximately half of the currently acidic lakes will improve chemically. This response will not be immediate since the watersheds may release previously retained sulfur into surface waters, causing a limited number of systems to further acidify. Biological recovery (e.g., self-reproducing fish populations) will require additional time; but stocking would result in rapid reestablishment of depleted sport fish after chemical recovery.

In the Southern Blue Ridge Region there are presently no acidic lakes. At current levels of deposition, projected changes could occur after the sulfate adsorption capacity of watersheds is exhausted, within 20 to 50 years. The projected number of systems becoming acidic under constant deposition is 10%[5].

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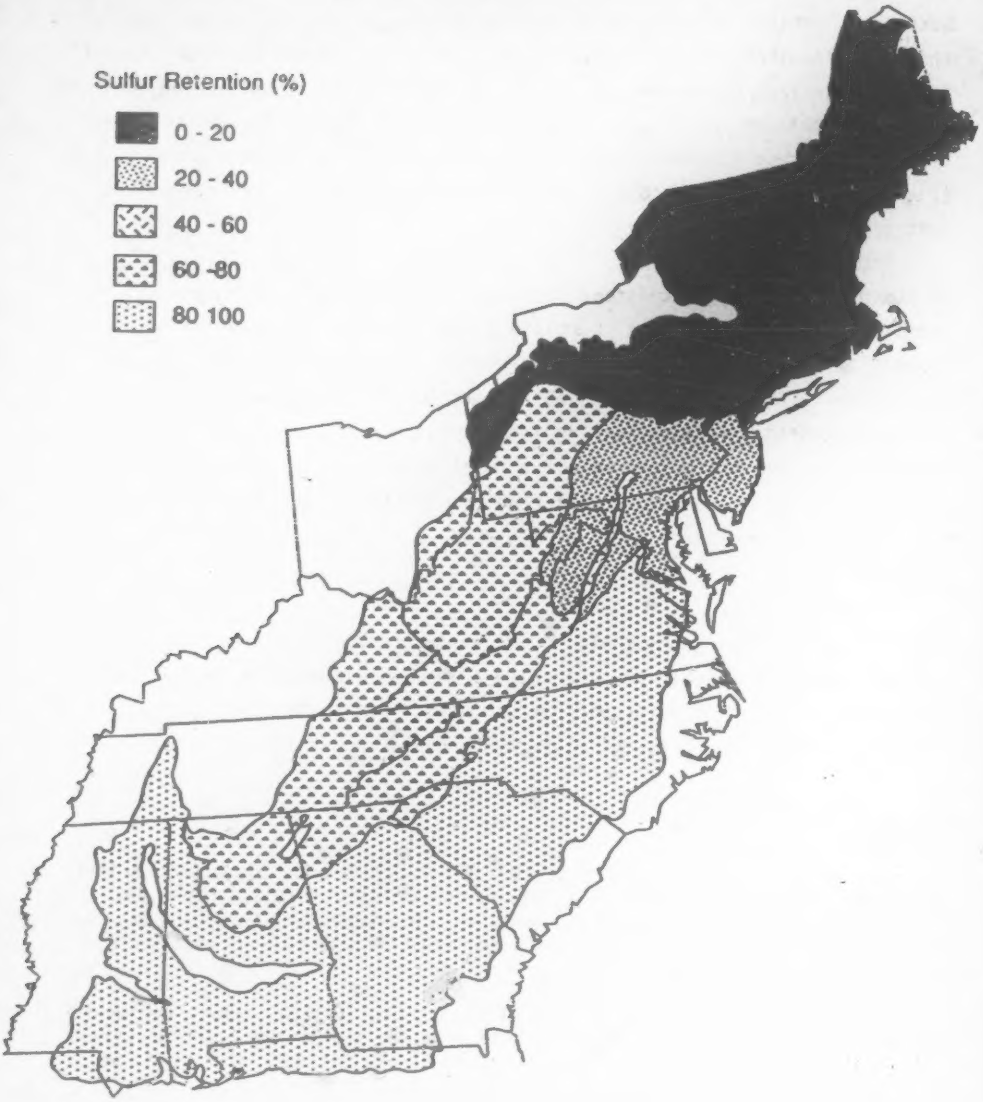
[4] An estimate of the current status of watersheds with respect to sulfate retention and storage capacity is important because any sulfate that is not retained and passes into surface waters will be accompanied by calcium and magnesium from the soils or, if there are insufficient amounts of these, by hydrogen (acidity) and aluminum.

[5] The 95% confidence interval on this estimate is ±15%. Thus, our best estimate is that 10% of the systems acidify. The number may be as large as 25%. Alternatively, models project that 5% of the systems increase in ANC.

Figure 2. Median Percent Sulfur Retention


Sulfur Retention (%)
0 - 20
20 - 40
40 - 60
60 -80
80 100

With a 20% increase in deposition, we project 12%[6] may become acidic. Biological impacts would generally follow as waters become acidic. Decreased deposition would likely decrease the rate at which acidification occurs.

The current status of surface waters in the Mid-Atlantic Region, including estimates of the numbers of acidic and sensitive systems, is known (Tables 2 and 3). Projections of future conditions are underway. Significant research for this region is being completed and will be included in the NAPAP 1990 Assessment. This research was undertaken when NAPAP's National Stream Survey showed that sensitive surface waters occurred in some of the mid-Atlantic subregions. Additional analyses suggest that some acidification may occur within a few decades.

Effects on Forests

As a result of NAPAP research and other studies conducted during the past several years, significant advances have been made in evaluating the hypotheses on forest effects. Synthesis of the most recent information has resulted in the current view summarized as follows: (1) acidic deposition appears to intensify the effects of natural stresses upon red spruce at eastern high elevation locations; (2) other than for red spruce, extensive surveys of forest condition have indicated no evidence of widespread forest decline in North America related to acidic deposition; (3) ozone adversely affects forest health in parts of southern California, and possibly in some southeastern regions; and (4) cumulative effects of acidic deposition may reduce the fertility of some forest soils within a period of approximately 50 years.

Trees respond to a wide range of natural and anthropogenic stresses throughout their life cycles. Because of the long life cycle of forest trees (decades to centuries), the effects of these stresses accumulate over time and compound the problems of isolating the influences of air pollution, and more specifically acidic deposition, from other sources.

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[6] The 95% confidence interval on this estimate is ±16%. Thus, our best estimate is that 12% of the systems acidify. The number may be as large as 28%. Alternatively, models project that 4% of the systems increase in ANC.

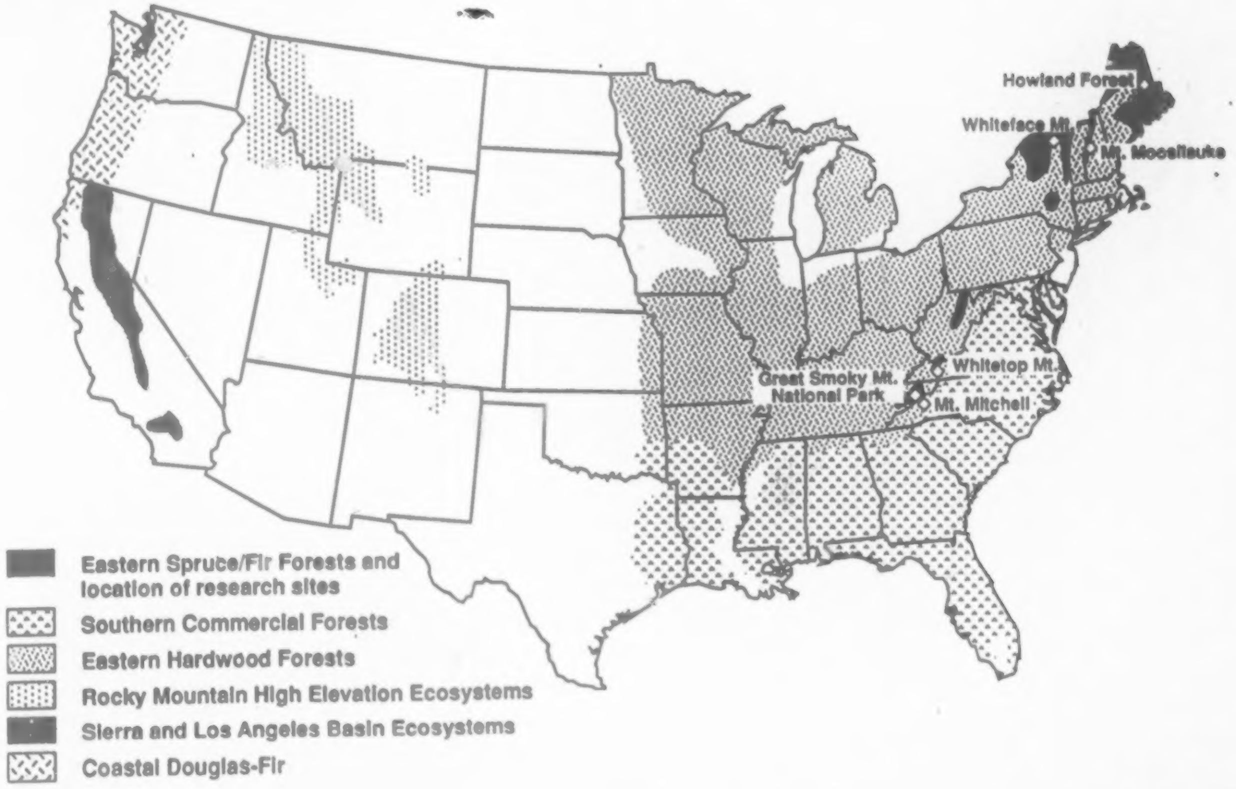
Two mechanisms of potential damage to forests from acidic deposition are usually considered: (1) direct impacts on the trees, and (2) indirect impacts due to alterations in soil chemistry. Direct impacts are more likely at high than at low elevations because forests are exposed to severe natural stresses as well as frequent exposure to cloud water containing acids often at higher concentrations than observed in rain. At some locations, ozone exposures are also greater at the higher elevations. Indirect impacts of acidic deposition due to soil chemical changes are of concern because such processes may be cumulative over large areas, with impacts becoming apparent over long time periods (i.e., decades). Soils at high elevations are often thin and poorly buffered, and these forests may also be the first to experience indirect impacts.

Figure 3 illustrates the range of the spruce-fir forests in the eastern United States, and indicates the locations of the NAPAP-sponsored spruce-fir research. Regions of other major forest types that have been studied in the NAPAP Forest Response Program are also shown. Decreased growth and increased mortality have been observed in some high elevation (above 2600 feet) stands of spruce-fir in the Northeast. In the Southeast, the spruce-fir stands are above 4500 feet and decreased growth has been observed in these stands. Several natural stresses are related to these declines, and acidic deposition from cloud water may intensify the effects of the natural stresses. Research aimed at confirming the possible importance of the acidic deposition stresses is continuing. Although the extent of these high elevation stands is limited (about 6% of the total area of eastern spruce-fir forests are at high elevations) they represent a unique ridge-top ecosystem.

Effects on Agricultural Crops

Research has established that there is no measurable and consistent adverse crop yield response from the direct effects of acidic rain at ambient levels

Figure 3. Research on Effects on U.S. Forests


Howland Forest
Whiteface Mt.
Mt. Moosilauke
Great Smoky Mt. National Park
Whitetop Mt.
Mt. Mitchell
■ Eastern Spruce/Fir Forests and location of research sites
▨ Southern Commercial Forests
▨ Eastern Hardwood Forests
▨ Rocky Mountain High Elevation Ecosystems
■ Sierra and Los Angeles Basin Ecosystems
▨ Coastal Douglas-Fir

in North America. Thus, the acidic deposition impact on regional crop production in the United States is considered to be negligible. An evaluation of the nutritional enrichment of some agricultural soils through the input of sulfur and nitrogen from acidic deposition indicates indirect benefits associated with decreased fertilizer requirements. Controlled studies suggest that on rare occasions fog acidity levels may potentially be high enough in the greater Los Angeles area to cause visible symptoms and thereby reduce the marketability of a few sensitive crops, such as strawberries. Nitrogen compounds are important constituents of such acidic fogs.

Average ambient concentrations of sulfur dioxide and nitrogen dioxide gases in most agricultural areas in the United States are not high enough or at elevated levels frequently enough to cause adverse effects on crop production on a regional scale. Effects may occur in local situations close to major sources (i.e., within a few kilometers). In contrast, controlled studies indicate that ambient levels of ozone in many regions of the United States are sufficient to reduce the yield of many agricultural crops.

Effects on Materials

Acidic deposition increases the rate of deterioration of some materials (e.g. galvanized steel and carbonate stone), some surface coatings (e.g. carbonate based paints) and some cultural resources (e.g. statues). The relationships between acidic deposition rates and deterioration rates for various materials have been studied in the NAPAP program. However, there are serious limitations in developing representative data and interpretive methods to isolate and inventory acidic deposition effects on exposed materials. Therefore, no generally accepted regional or national estimates of materials effects resulting from acidic deposition are currently available.

Deterioration of some exposed materials, partially attributable to acidic deposition, is recognized in major urban areas. Because of the large economic and cultural value of these materials, reduction of acidic deposition could have significant benefits in some cases. However, two factors limit the potential materials benefits which may result from reduction of acidic deposition levels: (1) acidic deposition is only one element of air pollution exposure for materials, particularly in major urban areas, where most of the nation's materials and cultural resources are located. Reductions in urban air pollution levels will likely create the largest materials benefits. (2) Maintenance and reconstruction activities are often undertaken for reasons unrelated to possible acidic deposition effects. Thus, at present, economic impacts due to materials deterioration cannot be estimated directly from the physical dose-response information. In its final (1990) assessment NAPAP will report bounding estimates of the materials benefits related to reductions in acidic deposition.

Economic Valuation of Benefits

Economic valuation methods have not been sufficiently tested for the full range of effects categories to support a comprehensive benefit-cost evaluation of acidic deposition control approaches. NAPAP is developing economic estimates of benefits in several categories, and will report them in its final assessment. Because of the limitations in currently available valuation methods, NAPAP has adopted three categories of benefits to compare between various control approaches. These categories of benefits are: (1) health-related benefits; (2) economically-evaluated benefits -- including market estimates such as productivity in commercial forests and behavior-based estimates such as for recreational fishing in lakes; and (3) conservation or ecological benefits -- including preservation of culturally important materials, remote lakes, and mountain forests for which obtaining credible economic estimates is particularly difficult.

Atmospheric Processes and Deposition

From 1979 to 1986, the majority of the wet deposition monitoring stations in the eastern United States showed an average reduction of the wet deposition of sulfate of 14 percent, although the trend was not statistically significant. The geographic regions of maximum deposition of sulfates and nitrates has remained relatively constant since 1983, and includes western Pennsylvania and New York, northern West Virginia, eastern Ohio, and Southwestern Ontario. In 1986 these maximum values were about 35 kg/ha for sulfates and 22 kg/ha for nitrates. This region also includes the region of highest rainfall acidity (pH <4.2).

Although the annual wet deposition of sulfate has decreased as the emissions of SO_2 have decreased since the 1970's, no apparent trend in the acidity of rainfall has been detected. Although this may be due in part to the inability of instrumentation to detect small changes in acidity, other factors such as neutralizing substances like calcium, ammonia, and oxidants in the atmosphere, should also be considered when evaluating patterns and trends of acidic deposition.

One of the major scientific issues addressed by NAPAP is the relationship between emission changes and deposition changes. Because of complex atmospheric reactions, percentage reductions in emissions may not result in similar percentage reductions in deposition at a particular location. In order to assess the importance of this non-linear relationship, NAPAP has devoted considerable effort to modeling the relationship between emissions and deposition through development of the Regional Acid Deposition Model (RADM).

Preliminary results from a few cases of this model suggest that non-linearity for wet sulfate deposition can occur in and near the region of maximum emissions density. The region of non-proportionality between sulfur dioxide emissions and wet sulfate formation may extend as far as 700 km downwind (generally to the north and east) of the major emission region of the Ohio River Valley. This suggests that emissions changes in the Ohio River Valley and eastern United States may result in less than proportional reductions in wet deposition in the downwind region. However, dry deposition, an important part of the total deposition, is expected to change more linearly with emission changes.

Control Techniques

Near-term reductions in sulfur dioxide emissions can be achieved using currently available techniques including fuel substitution, physical coal cleaning in those situations where this is not already employed, and flue-gas desulfurization (FGD or "scrubbing"). In most cases, switching from high sulfur to low sulfur coal can substantially reduce sulfur dioxide emissions. Physical coal cleaning achieves 10-30% sulfur removal, and the current generation of FGD achieves 70-90% sulfur removal. Higher efficiencies can be achieved with the addition of special additives (e.g., adipic acid) to the sorbent. Low nitrogen oxide burners and combustion modification techniques are available to reduce nitrogen oxide emissions from most uncontrolled coal-fired boilers by 25% to 50% in some cases. In addition, lime or lime hydrate injection into the boiler or ducts, may be an effective means of controlling sulfur dioxide.

A number of innovative advanced combustion technologies are under development with the aim of achieving either higher removal efficiencies at similar cost to conventional technologies or similar removal efficiencies at lower cost.

- Integrated gasification combined cycle (IGCC) plants can potentially achieve over 99% removal of sulfur dioxide emissions and over 95% removal of nitrogen oxide emissions. This technology has been demonstrated. However, the 99% sulfur dioxide removal was achieved at higher cost than conventional FGD. Hot gas cleanup, currently unproven in a fully-integrated, high-efficiency system at a commercial scale, will be required to improve the costs.

- Atmospheric fluidized bed combustion (AFBC) can achieve 90-95% removal of sulfur dioxide emissions and 70-80% removal of nitrogen oxide emissions and is in the commercial demonstration phase.

- **Pressurized fluidized bed combustion (PFBC) is entering the commercial-scale demonstration phase, with prospects of higher** removal and conversion efficiencies (at higher costs) relative to AFBC.

Advantages of these clean coal technologies over flue gas desulfurization can include: improved energy efficiency (greater kilowatt output per ton of coal consumed), lower emissions of carbon dioxide (a greenhouse gas), significant removal of nitrogen oxide emissions, more manageable wastes, possible use of poor-quality coals, and potential for future export of both clean coal technologies and coal. Wide deployment of clean coal technologies in lieu of conventional techniques can be initiated only when adequate experience from full scale commercial demonstrations is available.

Schedule of NAPAP Reports

NAPAP will publish its assessment reports at various scheduled dates in the next twelve months, as described in the Plan and Schedule for NAPAP Assessment Reports, released in January 1989. In view of current Congressional interest in the NAPAP findings, we are providing all reports as quickly as practical, consistent with assuring thorough review processes for these documents. For the information of the Subcommittee NAPAP has scheduled completion of its reports as follows:

(1) Findings Update -- November 1989

This will briefly summarize principal new technical information which has become available in 1988 and 1989.

(2) State-of-Science and State-of-Technology (SOS/T) Reports (Public review drafts) -- December 1989
These 28 major reports have been in development throughout 1989, in accord with the January 1989 NAPAP Assessment Plan. These drafts are currently undergoing peer review and interagency review, and are planned

for release in early December. The draft reports will be publically reviewed during the NAPAP International Conference scheduled for February 1990.

(3) NAPAP International Conference on Acidic Deposition -- February 11-16, 1990

This conference will focus on critical review of NAPAP's 28 SOS/T Reports. Preliminary conference registrations have already been received from more than 600 scientists and other representatives of government, nongovernment and private organizations from over 30 countries.

Final revisions to these reports, incorporating the critiques discussed at the International Conference and the latest NAPAP-sponsored research data, will be completed by mid-1990.

(4) Integrated Assessment Report -- review draft in mid-1990, and final information by September 1990

NAPAP's Integrated Assessment, responding to all of the questions posed in the January 1989 NAPAP Assessment Plan, will be available for review beginning in mid-year and completed by September 1990.

PART 2 - KEY ACCOMPLISHMENTS DURING THE PROGRAM

Our scientific understanding of the causes, effects, and control approaches for acidic deposition has increased considerably over the past nine years. Work performed within NAPAP has greatly broadened the information available to evaluate acidic deposition, and has advanced our understanding of some of the fundamental ecological and physical processes impacted by our nation's use of energy. The following comments briefly note some of the principal contributions of NAPAP in two categories: (1) improvements in scientific knowledge and analytical tools, and (2) development of assessment methodology for complex environmental issues.

Improvements in Scientific Knowledge and Analytical Tools

Aquatic Effects

o The extent, location, and chemical characterization of low pH and sensitive (low acid neutralizing capacity) lakes and streams in the eastern U.S. and lakes in the western U.S. have been established.

o Models to project future chemical changes for alternative deposition scenarios have been created and are being tested using data from a watershed manipulation project in Maine.

o Methodologies to sample representative surface waters and watersheds and project those results to regional populations have been developed.

o Preliminary estimates of the extent, magnitude, frequency, and duration of episodic acidic stresses to aquatic systems (e.g., from snowmelt or intense rainstorms) are being completed.

o The differentiation between natural and anthropogenic acidification has been evaluated by analysis of historical information using sediment cores.

o Information on the physiological mechanisms of damage to fish from acidic waters has been developed to project biological responses associated with changes in the chemistry of surface waters.

o Selected aquatic effects mitigation techniques have been evaluated.

Terrestrial Effects

- Recently completed national surveys of forest condition have established credible and comparable data bases for the first time. These data bases provide baseline information for future evaluations of forest status in the United States.

- Standard guidelines have been established for diagnosing injury to eastern forest trees caused by air pollution (including ozone), pathogens, insects, and abiotic stresses.

- Scientific consensus that agricultural crops are not damaged by acidic deposition has been achieved by eliminating the major uncertainties in this area through research and assessment.

- Continued studies have allowed further refinements of crop response functions for more accurate estimations of agricultural losses from ozone.

- Innovative techniques for studying the effects of stress on plants have been established and have provided important information on basic plant processes that will prove useful for many types of scientific inquiries.

Effects on Materials

- Better identification of the types of materials most susceptible to physical damage from acidic deposition has been made.

- Dose-response functions for several materials have been established by laboratory experiments and controlled field exposures.

- The economic importance of the susceptible materials and consumer maintenance practices associated with their use has been studied.

Emissions

- The first comprehensive inventory of natural and anthropogenic emissions associated with fossil fuel combustion was established for 1980. The 1980 inventory was updated for 1985 emission sources, using improved estimation methodology, data collection techniques, and quality control procedures.

- An integrated emissions modeling set, allowing projections of future emissions expected to result from changes in population, economic activity and control technology costs, has been developed. This model set is being used to project control costs, fuel mix, labor impacts and emission levels for several future scenarios.

Source-Receptor Relationships

- Advances in monitoring networks, improvements in emissions inventories and trends, and the considerable advances in atmospheric modeling technology made in NAPAP-sponsored research projects will allow us to assess source-receptor relationships with a much higher degree of confidence than in the early 1980's.

- The most comprehensive model of atmospheric processes associated with acidic deposition, the Regional Acid Deposition Model (RADM), was developed by NAPAP and is being used as both a research tool and an assessment tool. RADM will significantly improve our capability to analyze a range of regional and national scale atmospheric chemistry issues.

Control Measures

- Cost information has been gathered from 15 site-specific retrofit emission reduction studies in Ohio, Kentucky and TVA which developed comparative information on FGD, coal cleaning, coal switching and other removal approaches. This information will be useful in developing realistic cost information for a number of control approaches.

- The current status of available and developing control technology has been analyzed. This includes improvements in FGD (scrubber) technology which yield higher removal rates and increased energy efficiency as well as developments in clean coal technologies.

Economic Analyses

- NAPAP has implemented an economics research and assessment program to value those acidic deposition-related effects to which economic methods can be credibly applied. This includes market effects (forests, crops, materials) as well as nonmarket effects (recreational fishing). Economic valuation of benefits will be reported where feasible in the NAPAP Integrated Assessment.

- NAPAP has developed the capability to estimate both the direct costs associated with emissions reductions and the indirect costs of control programs such as employment or GNP impacts.

Development of an Integrated Assessment Methodology

In its final two years, NAPAP has shifted emphasis from research to assessment activities. A comprehensive Assessment Plan was developed to promote wide communication of the assessment results, and to expedite general use of the information. NAPAP's assessment methodology provides a framework for continuing evaluation of the effectiveness of new emission controls during the 1990's. The NAPAP Integrated Assessment methodology also provides a working example for other important environmental assessments.

- NAPAP's final assessment consists of two parts: (1) a series of 28 State-of-Science/Technology (SOS/T) Reports documenting comprehensive technical information relevant to acidic deposition, and (2) an Integrated Assessment providing a synthesis of the technical information from the SOS/T Reports to assist policy-makers and the public in evaluating a wide range of questions concerning acidic deposition.

- The NAPAP Integrated Assessment is structured around a series of key questions to present comparative analyses and costs associated with various emissions reduction scenarios. Scenarios reflect differences in scope, timing, and location of controls.
- Scientific peer review, interagency review and open public review of the draft NAPAP reports are integral elements of the assessment methodology.
- An Oversight Review Board consisting of widely recognized outside experts has been established to provide counsel on NAPAP's approach to reporting its Integrated Assessment findings.

PART 3 - CONTINUED DATA COLLECTION AFTER 1990

Your invitation requested my views on the potential use of continued data collection after the NAPAP mandate expires in 1990. In response to your question, three categories of longer-term information needs are noted: (1) trend information for key parameters, (2) continuation of data sharing among all relevant government agencies, and (3) special studies to address unresolved or emerging technical issues.

(1) Importance of long-term trend information.

Trend monitoring of acidic deposition itself, and the various effects of acidic deposition, provide "real world" confirmation of the predicted consequences of emissions changes. The NAPAP-sponsored studies have greatly expanded the information available about pollutant emissions, atmospheric processes, and environmental effects. Trend data collection can be much less extensive than the measurements associated with intensive studies. In the absence of follow-up trend information, much of the value of NAPAP's intensive short-term studies would not be maintained.

(2) Continuation of data sharing among all relevant organizations. The NAPAP experience has demonstrated the advantages of sharing information gathering activity, as well as scientific analyses and reviews, among several organizations. NAPAP's reports have greatly benefitted from the interagency studies and technical reviews carried out at the federal level, and from collaboration with major state programs, such as the extensive lake surveys conducted by the Adirondack Lake Survey Corporation in New York State.

NAPAP is currently compiling a report summarizing the acidic deposition research and assessment activities being conducted by state, private, and other nongovernment organizations. We will forward this survey to the Subcommittee as soon as it is available, within 60 days. Many of the state environmental organizations have expressed their interest in having single-location federal coordination of acidic deposition studies during the next several years, to assure efficient planning of federal- and state-level technical studies.

(3) Special studies

The intensive NAPAP studies have provided the necessary information to address many of the key technical issues related to acidic deposition. Several unresolved technical issues remain. The decade of the 1990's will be particularly appropriate for such studies because regional emissions controls (i.e., as implemented in new legislation) would provide a unique natural laboratory for evaluation of the effects of emissions change. We consider the following technical areas to be important:

Emissions

- Further resolution of natural source emission estimates for nitrogen oxides and volatile organic compounds. In particular, better estimates of the variation of volatile organic compound emissions with season and latitude are needed. Significance: Natural sources of nitrogen oxides and volatile organic compounds constitute important components of the atmospheric budget of these acidic precursor pollutants. Accurate estimates of these emission rates are important in the formulation of regional control strategies.

Transport & Deposition:

- The completion of regional atmospheric model evaluation studies will improve the capability to determine the relationship between major sources and the resultant effects in specific regions. Significance: Further model evaluation and application will address more specific questions of importance in resolving issues such as the role of oxidants, source attribution, emissions trading, and effectiveness of control approaches.

- Continuation of non-urban air quality and deposition trend monitoring. Significance: These data are important for quickly verifying the air quality and deposition responses due to emissions reductions to measure the efficacy of controls.

Aquatic Effects:

- Continuation of long-term monitoring of surface waters is very important. Significance: Some surface waters have been impacted by acidic deposition. Verifying the predicted responses due to emission reductions is necessary to measure the efficacy of the controls implemented.

- The mathematical models for projecting watershed response to changes in deposition need further evaluation and development, especially for nitrogen and organic compounds. Significance: Information from fully verified watershed response models will help to evaluate the effectiveness of emissions reduction strategies.

- Continuing research on episodic acidification events (associated with spring run-off and severe storm events) is needed. Significance: Episodic pH depressions are of interest because of their potential effect on aquatic resources. Current projections of watershed response to emissions reductions do not consider episodic acidification.

Forest Effects:

- Completion of long-term forest response research, with emphasis on evaluation of response to multiple stresses, and continuation of surveys to monitor forest condition are needed. Significance: Evaluation of long-term forest response to multiple stresses, including ozone and acidic deposition, requires long-term field measurements.

Materials Effects:

- Continuing research is needed to distinguish local and distant source contributions. Significance: Since most of the nation's materials and cultural resources are located in urban areas, reductions in urban air pollution levels will likely create the largest materials benefits.

- Better damage functions are needed for several economically important materials, especially paints and other surface coatings. Significance: Damage functions for a greater range of materials will allow better economic estimates of materials impacts.

Mr. Chairman and members of the Subcommittee, this completes my testimony. I would be pleased to answer the questions you may have. Thank you again for the opportunity to provide this summary of the information being developed by NAPAP.

ATTACHMENT B

TESTIMONY OF
JAMES R. MAHONEY
DIRECTOR
NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

BEFORE THE
SUBCOMMITTEE ON NATURAL RESOURCES,
AGRICULTURE RESEARCH, AND ENVIRONMENT
COMMITTEE ON SCIENCE, SPACE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES

November 16, 1989

Mr. Chairman and Members of the Subcommittee, I appreciate your invitation to appear before the Subcommittee today, to present testimony on the research and development needs related to air pollution problems, particularly in light of pending proposals to amend the Clean Air Act.

NAPAP will complete its ten-year mandate in 1990 with the publication and public review of a comprehensive Integrated Assessment on the causes and effects of acidic deposition, combined with comparative analyses of the costs and effectiveness of various emission reduction strategies. NAPAP's twenty-eight *State-of-Science and State-of-Technology Reports* (SOS/T) to be published in December 1989, and its *Integrated Assessment* to be published in 1990 will provide extensive documentation, guidance, and recommendations on the major scientific and technological issues related to acidic deposition. Next month's SOS/T reports will include recommendations on research and monitoring needs within each specialization area, and the 1990 Assessment will summarize needs for the entire field.

My testimony today includes four categories for your consideration. These are:

1. Future research and monitoring needs.
2. Suggestions for future evaluations.
3. Continued development of control technologies and mitigation measures.
4. Collaboration among research sponsoring organizations.

Each of these categories is discussed in the following comments, and examples of research and monitoring activities that merit consideration in future research plans are noted in the latter part of the statement.

1. A continuation of research and monitoring will be beneficial in several areas. The NAPAP studies, as well as research conducted in other parts of the world during the 1980's have significantly reduced our scientific uncertainty about acidic deposition processes and effects. Continued research on important unresolved issues and trend monitoring would (a) maintain the benefits of the major information base developed by the NAPAP studies, (b) allow evaluation of the effectiveness and efficiency of the emission controls that may be adopted in new Clean Air Act Amendments, and (c) support future analyses of the linkages between control strategies for acidic deposition, regional ozone and greenhouse gas emissions.

   Our experience with NAPAP indicates that three types of research and monitoring activities would contribute critical information for future control strategy evaluations:

   A. Trend monitoring. Standardized monitoring programs, conducted at representative locations on a continuing basis, provide the best "ground truth" information allowing us to interpret long-term changes in emission levels, air quality, deposition levels and ecosystem conditions. The scientific models used to link emissions, deposition levels and ecosystem conditions have significant uncertainties, and long-term trend information is useful to support future projections of all these parameters within acceptable uncertainty limits. For efficient development of the appropriate information, trend monitoring protocols should be reviewed to insure consistent time and space coverage of all trend parameters (emissions, air quality, deposition levels and effects).

B. Long-term effects.

In addition to continuing trend information, it would be desirable to continue several key studies that address long-term, multiple stress processes and their cumulative effects. For example, it is not possible to compress a 10- to 20-year (or more) forest productivity study into five years. Long-term process studies of forest productivity, soil chemistry, and surface water chemical and biological responses (including episodic responses) to acidic deposition would improve the information already developed in NAPAP studies.

C. Other specialized studies to fill information gaps.

Projections of future ecosystem impacts of acidic deposition require the use of scientific models and specialized data bases to extend current measurement data, and to estimate the effects of the changes in regional atmospheric chemistry and deposition patterns expected to result from new emission controls. The NAPAP 1990 *Integrated Assessment* is being developed with the use of approximately forty different process and effect models. Uncertainties are inevitable in these models, given our limited current understanding of very complex natural processes. NAPAP assessment studies are identifying the most important model uncertainties and data limitations. Among the important information needs are better understanding of integrated ecosystem processes, health effects, and the impacts of acidic deposition on exposed materials in communities.

2. The methodology to assess control strategy options could be further developed, with greater emphasis on risk evaluation and communication, and economic cost and benefit studies. NAPAP has conducted major research studies, but has a less extensive body of information and practice to use as a basis for risk evaluation and communication, and for economic cost and benefit evaluations. Following implementation of a new acid rain control program, it would be desirable to evaluate the impacts of the program on various ecosystems. Risk and economic evaluation information would be needed for development of effective public policies which prioritize risks, and for balancing control costs and related benefits. The NAPAP assessment methodology adopted in January 1989 after extensive public review could be used to evaluate the benefits of any new controls resulting from legislation. The NAPAP assessment approach (which is also relevant for other environmental assessments, such as questions of global change, regional oxidant control and toxic substances in the environment) includes:

   o A formal assessment plan, that indicates how research information will be used to answer specific questions important for policy evaluation.

   o Review of the assessment plan (original and updates) by all interested individuals and groups.

   o Documentation of the models and data bases used in assessment projections.

   o Explicit treatment of uncertainty in assessment findings and projections.

   o Extensive peer review and public review, including independent scientific commentary on the entire assessment approach.

It would be desirable that future evaluations of controls associated with possible amendments to the Clean Air Act include regional ozone and greenhouse gas issues. NAPAP's authorizing statute (P.L. 96-294) focused research and assessment on acidic deposition control issues. We now recognize that three important environmental issues, (a) global change (including regional scale processes and effects), (b) regional patterns of elevated ozone concentrations, and (c) regional acidic deposition patterns, have overlapping research, monitoring and technology evaluation needs.

3. Continued development and demonstration of mitigation and control technologies should be pursued. Because of the long time typically required (e.g., many years) for development and demonstration of advanced combustion and emission control technologies, such development should be continuously supported in advance of specific regulatory requirements. For example, current DOE sponsored development of advanced NO_x controls and combined SO_2/NO_x controls for stationary combustion sources should be continued, in addition to the several SO_2/NO_x emission reduction technologies now being demonstrated in the Clean Coal Technology (CCT) program.

In addition to development of emission control technology for conventional energy sources, each of the following should be encouraged:

- energy conservation methods and implementation (always a high priority, because the benefits include resource conservation, reduction of emissions, and fuel cost avoidance),
- renewable energy technologies and systems,
- alternative fuels.

Mitigation measures for near-term recovery of acidic lakes. The NAPAP aquatic studies indicate the time scale for recovery of currently acidic lakes in the Northeast (regardless of the cause of their acidification) is a few decades or longer. Liming has the potential to accelerate the restoration of acidic waters to a chemical state where fish and other organisms can survive. If chemical and biological recovery of currently acidic lakes on shorter time scales is desired in specific regions (for example, to restore lakes important for recreational fishing use), evaluations of liming and fish stocking, and other mitigation measures could be pursued. Current studies of in-lake mitigation should be supplemented with evaluation of lime applications to watersheds of recreationally important lakes.

4. Collaboration among federal agencies, and among federal, state and nongovernment sponsors of research and assessment should be continued.

The NAPAP program has demonstrated significant benefits resulting from federal interagency sponsorship, review and reporting of acidic deposition studies. Efficient use of federal research budgets has been realized, and the multiple agency reviews of research plans and draft reports have been effective in improving the quality of the research findings. NAPAP has recently completed a survey of state and nongovernment organization sponsored research on acidic deposition, which identified almost 1100 nonfederal sponsored research projects in the United States. (NAPAP will report on this state and nongovernment sponsored research next month; copies of the NAPAP report will be sent to all members of the subcommittee as soon as they are available.) To promote efficiency in research budgeting, and to foster wide review and use of available research, continuing collaboration among the federal agencies, state governments, universities, and nongovernment organizations should be pursued. A clearly identified focal point for this collaboration would help assure efficiency in research planning and review of results, and would facilitate integration of the research information available from various sponsors into assessments of control options.

Examples of Research and Monitoring Activities That Merit Consideration in Developing Future Research Plans

NAPAP's studies have identified areas that merit consideration for further research. We understand that each area must be further evaluated on its scientific merits and in the context of overall research priorities within the Federal agencies and departments. The following lists have not been prioritized:

A. Examples of trend information

- Emission trends for SO_2, NO_x, VOC and CO_2, using a consistent methodology to allow year-to-year comparisons.
- Air quality trends for non-urban locations, relevant for describing regional concentration patterns of sulfur, nitrogen, oxidant and selected hydrocarbon compounds.
- Air quality trends in selected urban areas, to allow urban-nonurban comparisons.
- Wet deposition trends with sufficient coverage to define the range of deposition in individual precipitation events, as well as typical seasonal and annual variability.
- Dry deposition trends for a characteristic range of exposures. (Dry deposition is inferred indirectly from turbulent flux measurements, and varies markedly as local surface conditions vary.)
- Trends in surface water (lake and stream) chemistry and biological productivity, with coverage adequate to extend the record of the NAPAP aquatics studies throughout the 1990's and beyond.
- Periodic resampling of watershed and forest soil chemistry, to extend earlier NAPAP field measurements.
- Trends of forest health and productivity, including managed, unmanaged and high elevation locations, to extend current NAPAP measurements.
- Long-term surveys of materials degradation for a representative sample of material types, exposures and deposition levels.

B. Examples of long-term process studies.

- Studies of the geochemical processes by which acidic deposition affects water quality and acidity in sensitive waters.

- Forest ecology studies at selected representative locations, with emphasis on evaluation of productivity, population changes, and mortality resulting from multiple stresses.
- Studies of materials degradation for a number of urban and nonurban structures, to evaluate the importance of local and distant source contributions.
- Evaluation of the Regional Acid Deposition Model (RADM), using nonurban air quality and deposition information to analyze responses to emission changes as differentiated from changes due to event, seasonal and interannual variability.

C. Examples of special studies to fill information gaps

- Further analysis of natural source emissions for nitrogen oxides and volatile organic compounds, as compared to anthropogenic sources.
- Further development of the mathematical models for projecting watershed responses to changes in deposition, especially for nitrogen and organic compounds.
- Continued research on episodic acidification associated with spring runoff and severe storm events.
- Research on the physiological mechanisms of tree responses (cell level, and needle and leaf level) to high acidity and oxidant exposures, both separately and in combination with natural stresses. This information is relevant for high elevation forest exposures.
- Continued research on damage functions for economically important materials, especially paints and other surface coatings.
- Measurements of short-term peak concentrations of acidic sulfate aerosols and nitric acid vapors, including the frequency of peaks and the time intervals between peaks.

- Continued controlled studies to examine the effects of air pollution stress with other important stresses (e.g. drought, pests) on crop production and management practices.

Mr. Chairman, this concludes my prepared testimony. I would be pleased to answer questions the Subcommittee may have.

TESTIMONY OF THE

COGENERATION & INDEPENDENT POWER COALITION OF AMERICA

TO THE

UNITED STATES SENATE

COMMITTEE ON ENERGY & NATURAL RESOURCES

JANUARY 25, 1990

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INTRODUCTION

The Cogeneration & Independent Power Coalition of America (CIPCA), a non-profit association representing the competitive power industry, appreciates the opportunity provided by the Committee to present this testimony.

CIPCA, together with its affiliated organization, the American Cogeneration Association (ACA), represents over 500 corporate and individual members interested in the development of qualifying facilities (QFs) under the Public Utility Regulatory Policy Act (PURPA) and non-QF independent power facilities (IPFs).

The competitive power industry is a new entry into the field of electric generation. Yet members of our industry have supplied about 20% of the new electric capacity that has been added in the United States in the ten years since PURPA was enacted and are expected to supply approximately 40 to 50 percent of new capacity over the coming decade. The further development of these facilities is essential to meeting the power needs of the country in a cost-effective and reliable manner.

Unfortunately, the Clean Air Act amendments currently before the Congress fail to recognize the existence of this increasingly important industry. CIPCA supports the proposed ten million ton reduction in SO2 emissions and endorses the emissions cap. However, we believe the legislation must provide for the construction and continued operation of power plants owned by independent developers.

EXISTING FACILITIES

A limited number of QF and IPF projects currently under development will be adversely impacted by the requirement to obtain allowances. Existing provisions of the Clean Air Act amendments create enormous uncertainties for these plants, which will need to obtain allowances for their operation after the year 2000. Power sales contracts have been signed or firm bid prices have been accepted for many of these facilities. The Clean Air Act amendments would impose upon these projects a new and unanticipated financial obligation to purchase allowances.

In order to allow these facilities to continue development as planned, without imposing inequitable retroactive requirements, we propose to create a class of facilities that has reached certain milestones as of March 31, 1990. This class of facilities would be treated as existing facilities under the legislation even though they may not come on line until after its enactment date.

CIPCA believes that the emissions from this limited number of facilities will be negligible, since they will be required under existing law and practice to meet new source performance standards using best available control technology. Most of these facilities will operate with emissions below .3 lbs/mmBtu, producing less than 20% of the emissions, in tons per year, of facilities with emissions levels of 1.2 lbs/mmBtu.

Therefore, CIPCA proposes that utility facilities that have received an approval in a state certification of need process, independent power facilities (IPFs) and PURPA qualifying facilities (QFs) for which a power sales contract has been signed with a utility and IPFs and QFs that have been selected by a utility in a solicitation process to supply power to that utility as of March 31, 1990, should be treated as existing units under the legislation regardless of the date of operation of these facilities.

ALLOWANCE TRADING

There is substantial doubt whether allowances will be freely traded. CIPCA's major concern regarding the proposed legislation is that allowances will not be available to new units due to the lack of a thriving market in allowance trading. In theory, the incentive for a plant owner to over-control is the profit to be made from selling allowances to others. In practice, it is difficult to imagine a utility creating allowances other than for its own use. While a small amount of allowances may be created because control technology is not an exact science, it is extremely speculative to assume that allowances created in this manner will be sufficient to meet the growing need for additional capacity.

Emissions allowances will likely be regarded as assets needed to meet a utility's future growth. Where allowance prices are rising, as they are likely to do in the short run, utilities would be prudent to hold allowances for their own use rather than face the chance of having to purchase more expensive allowances in the future.

Most utilities have access to more allowance creating options than do independent developers. Utilities can over-control at affected units or elect to include additional units under the program. Independent developers have neither of these options and must purchase any needed allowances on the market. For these reasons, CIPCA believes a sensible approach would be one that requires utilities to provide allowances to their suppliers. A utility should be obligated to provide allowances for any facility that sells power to that utility and requires allowances.

If the allowance market is tight, as we expect it to be, all utilities may not have access to allowances. In order to provide a pool of allowances that would be accessible in the event allowances were not available on the open market, CIPCA supports the provisions of S. 1630 that establish a set aside of 2% of the total amount of allowances created under the legislation. CIPCA believes that this pool of set aside allowances should be auctioned off by EPA to those utilities needing additional allowances for new facilities (either for their own new facilities or for those of their suppliers).

INDUSTRIAL BOILERS

Under the current provisions of the legislation, an industrial company that opts in to the allowance system would lose any allowances created through "reduced utilization or shutdown" of the boiler. An independent power producer may enter into an arrangement with a paper mill, for example, where the mill shuts down its dirty boiler and agrees to purchase steam from a cleaner cogeneration facility that the independent power producer will build. Cogeneration facilities produce two products, steam and electricity. In this instance the cogeneration facility would be providing steam to the industrial user and electricity to the utility company. The independent power producer owner of that cogeneration facility should be able to purchase from the paper plant the allowances created by replacing the heavily polluting boiler with a cleaner cogeneration facility.

Allowances that are created as a result of opting into the system by industrial hosts of cogeneration facilities should continue to be available to cogeneration facilities to the extent that a cogeneration facility replaces a previously operating industrial boiler.

POST 1985 UNITS

The Senate bill requires units that come on line between 1985 and the date of enactment to restrict emissions to the unit's annual fuel consumption at 65% capacity factor times its permitted emissions level divided by 2000, unless allowances are obtained for the additional emissions.

Unlike many utility plants, which may operate at about 65% capacity factor, most IPPs and QFs have been designed to operate at a capacity factor nearer 100%. Revenue streams for project financing have been calculated at that higher level and without the inclusion of costs for the purchase of allowances. The requirement in the Senate bill would put many of these projects into default. This provision should be eliminated and replaced with a requirement that these projects not exceed permitted emission levels in a baseline year to be determined by the Environmental Protection Agency on a project specific basis.

CONCLUSION

Acid rain mitigation should be a priority for the United States and the Congress. CIPCA fully supports a ten million ton reduction in SO2 emissions and the imposition of an emissions cap to forestall future emissions increases. However, CIPCA believes that the amendments to the Clean Air Act proposed in S. 1630 impose impossible burdens on the growing competitive power market. With the simple amendments we have suggested, these burdens can be eased and competitive power development and significant emission reductions can each proceed.

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Christine L. Nolin
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UNFAIR IMPACT OF ALLOWANCES TRADING ON QFs AND IPPs

The emission allowance provisions of the Clean Air Act amendments under consideration by the House and Senate would have a substantial detrimental impact on qualifying facilities (QFs) and non-QF independent power projects. The further development of these facilities is essential to meeting the power needs of the country in a cost-effective, reliable manner. Pending legislation does not reflect the growing competition in the power generation market. The following problems need to be addressed:

- A limited number of QF and IPP projects currently under development will be adversely impacted by the requirement to obtain allowances. Power sales contracts or firm bid prices for these projects have already been established. The amendments would impose upon these projects a new and not anticipated financial obligation to purchase allowances.

- There is substantial doubt whether allowances will be freely traded. Utilities have an obligation to meet consumer demands for power and will need allowances to meet these obligations. Most, but not all, utilities will be able to generate the allowances they need. In contrast, most QFs and IPPs will not be able to generate their own allowances. Yet, QFs and IPPs are projected by DOE and other sources to supply as much as one-half of the power generation capacity needed by utilities over the next decade.

- By requiring the surrender of allowances when old boilers are shut down, the amendments impose a penalty on industrial facilities that seek to improve their energy efficiency and costs through the installation of cogeneration facilities.

- The Senate bill restricts emissions to a level consistent with traditional utility capacity factors. QFs and IPPs operate at significantly higher capacity levels.

The following amendments are recommended to resolve these problems:

1. To prevent inequitable retroactive impacts, the legislation should provide that facilities that have received a certificate of need through a state regulatory process and facilities that have been selected as winning bidders in a utility solicitation process or for which a power sales contract has been signed as of March 31, 1990, should be considered existing units.

2. Utility purchasers of QF or IPP power should have the obligation to provide needed allowances. To ensure an adequate supply of allowances for all utilities, at least 2% of all allowances should be set aside to be allocated by EPA in consultation with DOE and FERC.

3. Industrial facilities that shut down old boilers should be permitted to retain allowances if the purpose of the shut down is to install a cogeneration unit.

4. Allowances should not be allocated based on a uniform, legislatively determined capacity factor. Rather, emission levels should be determined by reference to an appropriate baseline year determined on a project specific basis.

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STATEMENT BY
ASSOCIATION OF HOME APPLIANCE MANUFACTURERS
TO THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
FOR THE RECORD OF THE
JANUARY 24-25, 1990 HEARING ON
THE ENERGY POLICY IMPLICATIONS OF
S. 1630 CLEAN AIR LEGISLATION
JANUARY 22, 1990

The Association of Home Appliance Manufacturers, which represents the manufacturers of virtually every refrigerator and freezer sold in the United States today, supports our government's immediate focus on steps that are known to effect climate change, such as reducing chloroflurocarbon gas emissions, increasing energy efficiency, and promoting reforestation.

Refrigerator/freezer manufacturers have relied on CFCs for the past 30 years as a basic refrigerant gas and, more recently, as a blowing agent for highly energy efficient foam insulation.

CFC-11 and -12 are rapidly being phased out through international agreements, and this process will be accelerated if the Clean Air Amendments (S.1630) are enacted.

As an industry, we are working with our government to solve the practical problems presented by this global challenge.

The appliance industry, with the Environmental Protection Agency and the Department of Energy, is actively attempting to find acceptable substitutes in order to develop new technologies for household refrigeration through the Appliance Industry/Government CFC Replacement Consortium, Inc.

We need at least three years after CFC substitutes and accompanying technologies are identified to redesign and retool to mass produce new products.

However well-intentioned, CFC elimination presents our industry with a dilemma. The Department of Energy just issued highly stringent 1993 energy efficiency standards. The standards will require redesign and retooling of an estimated 99.7% of the refrigerators and freezers we make.

We will have to continue to use CFCs and perhaps greater amounts of CFCs to meet the standards because there are no known commercially available substitutes with the same energy efficiency characteristics. CFCs have been the basis for a 75% energy efficiency increase over the past 10 years, while maintaining the reliability and low cost of these essential products.

Some of our members are already having difficulty obtaining adequate CFC supplies. The supply situation may get worse in the near future as CFC phaseout continues. If it does, we may need help -- either in the form of assured supplies of CFCs or relief from DOE's 1993 standards.

STATEMENT OF DAVID LEE MOHRE

EXECUTIVE VICE PRESIDENT AND GENERAL MANAGER

CAJUN ELECTRIC POWER COOPERATIVE, INC.

SENATE ENERGY COMMITTEE HEARINGS
ON THE CLEAN AIR ACT

JANUARY 24, 1990

Statement of David Lee Mohre

Executive Vice President and General Manager

Cajun Electric Power Cooperative, Inc.

SENATE ENERGY COMMITTEE HEARINGS ON THE CLEAN AIR ACT

My name is David Lee Mohre. I am Executive Vice President and General Manager of Cajun Electric Power Cooperative, Inc., a $3.2 billion generation and transmission corporation with over 1900 MW of coal, gas, and nuclear generating capacity that supplies electricity to over one million residents in a service area that covers 80% of the state of Louisiana. I have been in the utility arena for over twenty-six years -- twenty-one of which have been with cooperatives and investor-owned utilities.

I have also managed federal policy, research and regulatory programs related to the electric industry for five years at the Energy Research and Development Administration and later the Department of Energy. Before I left the Energy Department in 1980, I established and managed the Power Distribution and Load Management Research and Development Program, and was named Administrator of the Defense Electric Power Administration and Deputy Director of the Division of Power Supply and Reliability, responsible for managing federal programs required by the Federal Power Act, the Defense Production Act, the Industrial Fuel Use Act, the Public Utilities Regulatory Policies Act et. al., designed to ensure the adequacy, economy and reliability of the nation's bulk power system in peace time and in national emergencies. During this period I also directed the federal analysis of TMI-related generic and "lessons-learned" shut-down scenarios for the Nuclear Regulatory Commission.

I am a former member of the EPRI/NARUC National Rate Design Study Committee, the EPRI Energy Utilization and Conservation Technology Task Force, Chairman of the EPRI Industrial Program, the FERC Advisory Committee on Power Pooling and several other energy related organizations. I currently serve on the Board of Trustees of the North American Electric Reliability Council (NERC).

Cajun Electric began electric power production in 1972 with the operation of two small gas generators. With Louisiana growing quickly, Cajun found that it needed to increase its generating capacity by the mid to late 1970's.

At that time, Congress passed two important pieces of legislation which would affect utility generation and operating costs particularly in states like Louisiana whose generating resources were essentially 100% natural gas fired at that time. One law, instituted to save natural gas, was the Industrial Fuel Use Act of 1978 which substantially eliminated natural gas, and oil, as a utility boiler fuel. The second law, the Clean Air Act amendments of 1977, put in place strict new emissions regulations. At that time, choices for new generation were substantially limited to coal and nuclear power. Cajun chose to focus principally on coal-fired generation and embarked on the construction of three 540 MW coal-fired units, the first coal-fired units in Louisiana. Currently 80% of an energy production is coal-fired.

The 1977 Clean Air Act amendments instituted New Source Performance Standards (NSPS) that required all new coal-fired plants to meet SO_2 requirements of 1.2 lbs/MMBtu and NOx requirements of 0.7 lbs/MMBtu. This standard forced Cajun to purchase low sulphur coal from the West which Cajun ships from Wyoming some 2,000 miles along rail and barge routes. Our annual transportation bill for shipping this very low sulphur coal has exceeded $100 million per year. Our generating units also are equipped with state-of-the-art electrostatic precipitators (ESP's) to control particulate matter following combustion of coal. These ESP's were required by NSPS regulation, and capital costs were in excess of $30 million per unit. With this combination of low sulphur coal and ESP's, Cajun's coal-fired units met, and still meet, all of the requirements of the present NSPS regulations. As a good environmental citizen whose Board and management are committed to a clean environment, Cajun Electric, and we believe all Louisiana utilities can support cost-effective amendments to the CCA that will achieve the stated objectives, so long as the enabling legislation does not penalize those clean utility systems that have already made large investments in emissions reductions and whose consumers have been, are, and will continue to pay for clean air.

Because of the profound effect of some of the current clean air proposals, we respectfully point out that any consideration of Clean Air Act amendments is in reality a consideration of our national energy policy, our economic policy and our environmental policy – and not just environmental policy alone. America's position in the world marketplace demands that we establish energy and environmental goals consistent with our nation's need for economic growth, along with protection of national security.

As a consequence I would like to submit the following comments for consideration:

1. We believe that any discussion of amendments to the Clean Air Act must directly and specifically include related long-term national energy issues. Appropriate consideration must be given to such energy issues as the impact of changes to the Clean Air Act on long-term energy availability, energy security and price. The statistics are clear. While the United States accounts for 27% of annual world oil consumption , we have less than 4% of the world's known oil reserves. Recently we have had a number of days where we have imported over 50% of our oil needs. In addition to these energy security and economic issues, we must also understand that our domestic price for energy will affect competitiveness of U.S. goods and services abroad. While talk about establishing a moral imperative for the world is compelling, economic reality suggests that we must be careful not to price ourselves out of the work market place and eliminate the national future use of our most plentiful domestic energy resource. Given that current U.S. coal reserves are 43% greater than the world's known oil and gas reserves combined, we must not to rule out the future use of this much needed domestically available energy resource. As the recent WORLD ENERGY OUTLOOK, (published by

Conoco), pointed out, there is no way that oil and gas alone can supply the incremental energy needs of the world and, particularly, the United States alone in the future. We are going to need everything we've got.

2. With regard to coal-fired electric generation, we would ask that a discussion be held as to whether such a complex bill is really needed. Politically it may be, but logic suggests that all we need to do to meet the present stated goal of 10 million tons per year reduction SO_2 is to make all utilities in the nation meet the same standards that we at Cajun meet and all the utilities using coal in Louisiana meet, that is, make all the utilities in the nation meet New Source Performance Standards that are currently on the books. No complex allowance system, no larger bureaucracy, no federal state arguments over who's in charge, no high legal bills, and no unfair competition for economic growth due to hoarding of limited emission allowances.

   Simply make those that are causing the problem and typically charging lower electric rates because of that, meet NSPS and pay the cost clean utilities such as Cajun and its customers do.

3. As a member of the Board of Trustees of the North American Electric Reliability Council, as one who is familiar with the operation of integrated and interconnected electric utility systems on a regional and national basis for the past 28 years, I would ask that specific consideration be given to the potential impact of any Clean Air Act changes on the reliability and economic operation of the nations bulk power system. Within the past month we have seen extremely cold weather cause severe rotating blackouts in many parts of the country. These rotating blackouts and the nonavailability of electricity have enormous economic consequences and enormous social consequences. Therefore, I believe it is only prudent that before adopting amendments to the Clean Air Act that appropriate consideration be given to the impact on the reliability of the power system which is so fundamental to our nations economic engine and social well-being.

4. If, despite the logic that suggests to us that the only action needed to meet the President's goal is to make NSPS the standard for all utilities in the nation, then we would like to suggest that the following concepts be included in any Clean Air Act Amendments:

a. No mandatory scrubbing of units should be included in the bill, thus giving utilities the flexibility to reduce SO_2 in the most economic manner.

b. No tax or other methods of cost sharing that would result in clean utilities, whose consumers are already bearing the higher cost of clean air, helping to pay for the clean up of those who have not met the New Source Performance Standards that have been on the books for over a decade.

c. A utility exemption from toxic air regulation until such time as there exists a competent data base.

d. Flexibility in trading, buying and/or selling, any SO_2 credits or allowances that may result from the new bill.

e. Elimination of the potential ability of non-NSPS utilities, through their own efforts or prohibition by their state regulatory commissions and/or state government, to hoard emission allowances needed for economic development in areas/states served by clean utilities.

Additionally, we would like to list the following items of concern with regard to wording of several proposed amendments to the Act:

a. **Emissions Rate Cap On NSPS Sources**
Existing coal-fired plants, which meet the present NSPS standard of 1.2lbs/MMBtu, will be required to operate at or below their actual 1985 emission rate. Cajun's units operated at less than this standard, but there is no guarantee that future coal quality will remain in order to meet our very low 1985 emission rate, and penalties for emission exceedances are stiff under this proposal. Clean utilities should not be unduly penalized for the operation of clean power plants, at least until all coal-fired plants in the nation meet NSPS standards. Let the relative punishment fit the relative crime.

b. **New "Greenfield" Plants Require an SO_2 Offset**
Cajun, and other "clean" Louisiana utilities using coal, would be required to buy offsets of SO_2 emissions in order to build new coal-fired generating plants. Under the current proposal, clean utilities would not obtain any "allowances" since we already operate at NSPS levels. Therefore,

additional generation will more expensive due to the need to purchase SO_2 credits from dirty utilities in other states — assuming those credits would be available. Again, clean utilities are penalized while the owners of older units with minimal pollution control are dealt an invaluable asset that could control the economic well-being of a state or region.

c. **No Variance Provisions**

There are no short-term variance provisions contained within the proposal for disruptions such as nuclear outages, gas curtailments, coal strikes or transportation problems. A variance provision should be provided for unusual circumstances.

The Board and management of Cajun Electric Power Cooperative, Inc. and the more than 1,000,000 rural Louisianians we serve appreciate your consideration of the above.

WSPA
Western States Petroleum Association

Douglas F. Henderson
Executive Director

January 22, 1990

The Honorable J. Bennett Johnston
Chairman, Senate Energy and Natural
Resources Committee
Dirksen Senate Office Building
Room 364
Washington, D.C. 20510

Subject: Comments of the Western States Petroleum Association on S1630

Dear Mr. Chairman,

The Western States Petroleum Association (WSPA), representing a wide spectrum of companies that develop and market petroleum and petroleum products in the Western United States, understands that your Senate Energy and Natural Resources Committee will hear testimony on S1630 on January 25, 1990. WSPA submits the attached statement for the hearing record.

The statement focuses on the Outer Continental Shelf (OCS) air quality/jurisdiction issue, particularly as it regards the use of emission data from the Santa Barbara County Air Quality Attainment Plan (AQAP). Should you or your Committee need further information, I will be happy to assist you.

Very truly yours,

Douglas Henderson (ja)

ccs: Mr. Phil Holladay
Mr. John Peschke

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STATEMENT OF WESTERN STATES PETROLEUM ASSOCIATION

BEFORE THE SENATE ENERGY COMMITTEE

ON

S-1630

CLEAN AIR ACT AMENDMENTS OF 1990

JANUARY 25, 1990

The Western States Petroleum Association (WSPA) is pleased to submit its views on Section 111 of S-1630, which would transfer regulatory authority for the Outer Continental Shelf (OCS) air emissions to the Environmental Protection Agency (EPA). WSPA is a trade association that represents the majority of producers, refiners and distributors in the six western states.

The Senate Environment Committee report dealing with oil and gas activity in the OCS contains serious errors and misrepresentations (see page 76 - 78). The prime source of this misinformation has been the Santa Barbara County Air Pollution Control District (APCD). Their representation of the impacts from oil and gas activity in the California OCS has been most recently summarized in their testimony before the Environment Committee and the recently published 1989 Santa Barbara County Air Quality Attainment Plan. As a matter of interest, three examples of misinformation from the Environmental Committee report are:

> "Operational emissions from an OCS platform ... routinely exceed 500 tons of oxides of nitrogen and one hundred tons of reactive hydrocarbons annually." (page 76) The facts are that a typical new platform as referred to emits less than 50 tons of NOx and 10 tons of HC annually (less than 100 tons NOx and 15 tons HC, if crew and supply boats are included) and that these emissions are fully offset.
>
> "... drilling a single exploration OCS well can cause in excess of one hundred tons of NOx." (page 76) The facts are that a typical exploration well has NOx emissions between 20 and 50 tons. It is true that when crew and supply boats are included, emissions from an exploration well could be as much as 100 tons of NOx, but the typical well has emissions more nearly half of this amount. These emissions are a temporary source of short duration. In the last two years, six exploration wells have been drilled off the Santa Barbara Coast. Finally, these emission numbers represent old technology. Existing technology will reduce them by as much as 40%.
>
> "... the potential that unmitigated OCS pollution will prevent certain coastal regions from attaining Federal Clean Air Standards." (page 77) The facts are that since 1978, OCS emissions have been mitigated and that they are far less important than onshore emissions and transport of pollutants from Southern California in how Santa Barbara will achieve attainment.

The County of Santa Barbara has misrepresented OCS activity and its impact on local air quality. This furthers their agenda to obtain jurisdiction for OCS activity. The "real world" development of California OCS resources represents much less of an impact and transfer of jurisdiction is not necessary to assure that emissions in the OCS are dealt with in a manner that protects air quality. We suspect that the agenda of many of those who wish to transfer jurisdiction is to achieve a shut down of OCS activity for reasons other than improving air quality. The issue of the appropriateness of OCS activity should be dealt with on its own merits, and not in the guise of protection of air quality against a backdrop of misinformation.

Three key points are important in understanding how best to deal with air quality issues associated with the California OCS.

1. OCS emissions associated with oil and gas operations are not as significant as presented.

2. Industry has done and will continue to do its share to minimize the impact of its emissions, including the use of best available control technology, offsets and electrification where appropriate.

3. While current MMS regulations do not require this type of control and full offsetting of emissions, alternatives to the proposed transfer of jurisdiction to EPA (and local authorities) have been proposed that would accomplish the objective of stringent air control requirements while also maintaining the viability of OCS activity.

There are several misconceptions regarding the contribution of oil and gas operations in the California OCS to the overall emission inventory that local air districts are using. Most of the OCS activity is located in the Santa Barbara channel area. Information developed by the APCD has been quoted stating that the OCS represents 37% of the emission inventory impacting Santa Barbara County's air quality and that this amount is more significant to local air quality and that this amount is more significant to local air quality than the emissions from mobile (vehicular) sources.

The clear, yet misleading, implication is that oil and gas operations in the OCS represent a very significant part of the emission inventory, more significant than onshore mobile sources. The facts are very different. Emissions associated with oil and gas operations in the OCS represent less than 5% of the inventory when it is compared with the corresponding onshore areas. The other numbers that have been included to create the 37% figure quoted are ocean going ship traffic emissions, other activities in the OCS such as fishing and pleasure boats, and natural seeps. That is not to say that these other emissions are not of interest and that they do not represent a concern to the local jurisdiction as it deals with attainment.

However, it is to say that they are not associated with the oil and gas operations in the OCS (nor would they be controlled under the transfer of jurisdiction proposed in Section 111.) The "real world" onshore impact of the oil and gas emissions is significantly less than even the 5% figure would indicate because of distance from shore and wind movement. In addition, the inventory numbers used by Santa Barbara County APCD overstate the actual OCS emissions, overstate the future growth of OCS emissions and understate the impacts of pollutant transport from Southern California. Use of more realistic emission estimates for current OCS activities, for future activities and for transport would still further reduce the perceived onshore impact of these OCS emissions. This number, significantly less than 5%, when compared to the 44% of the inventory associated with vehicular travel, represents an entirely different relationship than that presented in the generalization of the inventory figures.

What are the impacts of the actual oil and gas emissions from the OCS? The life of an OCS project goes through various stages. First there is exploration, then construction, drilling and finally production which represents approximately 90% of its life. There are peaks in emissions, such as when the platform is set in place during construction, but they are of short duration. The long term emissions occur during the production phase. The real impact of these emissions depend upon many factors, but it is significantly less than if they were located onshore. Clearly, it is not a 1:1 ration. However, recent development activities have been offset at an effective ratio greater than 1:1 and history has shown that future activities will be similarly offset as a minimum requirement.

A brief review of the recent history of development in the California OCS shows a continuing tightening of emission controls by the oil and gas industry. Following the end of the moratoria on development in 1978, sixteen platforms have either been installed or approved. Although modeling demonstrated that the 1978 Beta development off Long Beach did not have a significant impact on the Los Angeles Basin air quality, prior to its installation the air emissions were fully offset onshore. The same type of interrelationship with onshore concerns can be said for the other platforms installed since the lifting of the moratoria. The most recent platforms associated with Point Arguello and Santa Ynez developments gained the support of the local districts, by the agreement to state of the art controls and full offsets of the platform's emissions.

In this type of environment, OCS activity can continue to go forward with industry doing its fair share to solve air quality problems in Southern California. The history of activity since 1978 shows that the development of an OCS project is a joint effort involving the Minerals Management Service, the state, the local jurisdictions and the involved companies. Each local area has permit authority over some portion of a project that involves them in the entire project consideration. Projects have moved forward with the concurrence of the local jurisdictions, and air issues and other local concerns were dealt with to their satisfaction. Best available control technology and offsets for actual emissions are standards in this "real world" environment, as is serious evaluation of electrification.

The key area of concern of the Santa Barbara County APCD has not been the level of control, offsetting and mitigation that industry has provided, but the fact that MMS regulations did not mandate such requirements. Admittedly, the process for achieving industry's agreement for the controls, offsets, etc. demanded by the local jurisdiction has been difficult both for the local APCD and for industry. It has served, however, as the quid pro quo for gaining cooperation from the local entities in permitting necessary onshore facilities.

There are legislative and regulatory alternatives to the transfer of jurisdiction to EPA as proposed in Section 111 that would assure that this voluntary cooperation of the past would continue in the future. The key elements of a compromise would be a legislative requirement that MMS adopt regulations that provide for full mitigation and control of OCS platform emissions off the coast of California; i.e., no new net emissions off the coast of California OCS, retrofit requirements where appropriate and a program for working with the local jurisdiction for providing offsets/mitigation of the remaining actual emissions. What is being proposed by some is that MMS be required by law to adopt regulations that require industry to do what the local APCD has achieved with industry's cooperation in the past. This accomplish, but still maintains the framework of a viable OCS program.

A final reason for not enacting the language in Section 111 is that the concerns it attempts to address are found primarily along a relatively small section of the California coast line. However, the changes proposed affect the OCS throughout the United States. The alternative suggested, deals with the actual areas of concern and does not disrupt activity through out the OCS.

National Independent Energy Producers

Board of Directors

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  (Air Products and Chemicals, Inc./
  Browning-Ferris Industries, Inc.)
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January 23, 1990

Senator J. Bennett Johnston
Chairman
Committee on Energy and
  Natural Resources
United States Senate
364 Dirksen Senate Office Building
Washington, DC 20510

Dear Senator Johnston:

Enclosed is the clean air position paper of the National Independent Energy Producers (NIEP). As you know, the National Independent Energy Producers is an association of independent firms that generate electricity for sale to utilities and develop co-generation and alternative energy projects for a variety of users. We respectfully request that this letter and the accompanying position paper be distributed to all members of the Senate Committee on Energy and Natural Resources and included in the record of your hearings to be held on January 24-25, 1990, on the pending amendments to the Clean Air Act (S. 1630).

To summarize NIEP's position, we believe that both achievement of clean air goals and satisfaction of new energy generation needs are possible. We now meet new source performance standards and at many plants are significantly cleaner. NIEP is supportive of the general scheme of the acid rain provisions of the bill and particularly the objective of creating market incentives for air pollution control.

NIEP is concerned, however, that as presently drafted, S. 1630 could thwart competition in wholesale power supply markets and hinder the ability of independents to meet energy supply objectives of the next ten to twenty years. Under the bill, all new plants would have to have allowances to operate after the year 2000, yet allowances are allocated only to existing sources that exceed current new source performance standards. In particular, NIEP is concerned that:

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- the bill may not contain sufficient incentives to ensure the quick functioning of a robust market for trading allowances (so that new generating capacity can be financed and built by independents that have no initial allocation of allowances);

- utilities that receive an initial allocation of most allowances under the bill may be reluctant to sell them at all or, in particular, to independent power producers who may compete to generate and supply wholesale electricity;

- utilities that receive initial allocation of allowances may be willing to transfer allowances only to affiliated subsidiaries and to do so at subsidized rates that would preclude competition from genuine independents; and

- state public utility commissions may in some instances be reluctant to permit willing utilities to sell their allowances (particularly for out-of-state use).

NIEP is not saying the market for allowances envisaged by S. 1630 cannot and will not work. We are saying, however, that in light of these concerns, the bill needs to be amended to provide stronger assurances that needed allowances will be available in a free market for which independent, competitive power can compete fairly. Without such changes, it may be quite difficult, perhaps impossible, for independent power producers to obtain necessary financing for new plants planned for the 1990s and beyond.

To meet these concerns, the NIEP position paper recommends two sets of amendments to S. 1630. With these amendments, NIEP can and would support enactment of S. 1630 and retention of an inviolate cap on allowable SO_2 emissions.

The first set of amendments that NIEP recommends would strengthen and broaden the existing reserve provisions of S. 1630. The second set of amendments that are recommended in the accompanying position paper is designed to prevent anti-competitive use or misuse of allowances. This latter set of amendments would ensure a fair sealed bid procedure is observed for auction of the allowances initially allocated by the bill before a utility uses these allowances to build its own new plants or before first transfer of these allowances to a subsidiary to enable that subsidiary to build a new plant. This proposal is explained in greater detail in the accompanying position paper.

NIEP appreciates the opportunity to present these comments for the Committee's consideration. We would be pleased to respond to any questions the Committee may have with regard to this submission. In addition, we would appreciate the Committee directing the following set of questions to pertinent witnesses who appear at the hearings:

1. What is your response to the four concerns voiced by the NIEP in this cover letter?

2. What mechanisms are provided in the bill to ensure that sufficient allowances will be available to independent power producers to enable them to build new plants and compete to provide the lowest cost wholesale electricity?

3. What will be the likely effect on competitive power if these mechanisms turn out in fact to be inadequate to ensure the availability of necessary allowances? What recourse, if any, would be provided and how adequate would this recourse be for independents?

4. If the Committee were to conclude that additional mechanisms were necessary to ensure the expeditious functioning of an open, competitive, and robust market for allowances in which independents could fairly compete, what mechanisms would the witnesses recommend? How would these mechanisms help meet these concerns? How would the witnesses respond to NIEP's proposals?

Again, we appreciate the opportunity to submit these materials for the Committee's consideration.

Sincerely,

Merribel Ayres
Executive Director
National Independent Energy Producers

Enclosure

cc: Karl Hausker
[redacted]
Bill Conway

National Independent Energy Producers

Telephone: (202) 783-2244
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January 12, 1990

NIEP CLEAN AIR PROPOSAL: EXPLANATION AND JUSTIFICATION

I. STATEMENT OF THE PROBLEM

The National Independent Energy Producers (NIEP)[1] is committed to shaping the long-term future of competitive power generation. Competition in electric generation markets will help meet the nation's need for reliable low-cost electricity and the nation's environmental goals in the 1990s and beyond. Sources of competitive power are projected to contribute 40 to 50 percent of the United States' new electric generating capacity in the next 10 years. Clearly, independent generators in those competitive markets are emerging as vital suppliers to meet the demand for new electric generating capacity.

In general, NIEP supports the principles of the acid rain provisions in the Senate clean air bill, S. 1630; achieving reductions in SO_2 emissions by harnessing market forces; and a cap on SO_2 emissions. Both the Senate and House bills, however, allocate all SO_2 "allowances" to certain existing conventional utilities, while also requiring all new electric generating units to obtain allowances for SO_2 emissions. Independent power producers will not get allowances initially. To build a new plant, therefore, independent power producers will have to purchase allowances from the same utilities with whom they compete.

The absence of measures to prevent hoarding or discriminatory use of allowances in the original Administration bill and the House subcommittee bill could unintentionally halt the growth of competitive power generation in the United States. NIEP is concerned that independent power producers not affiliated with utilities may be unable to purchase necessary allowances to build these new plants. While the Senate Committee bill contains language that helps address NIEP concerns, this new measure provides limited relief and contains no prohibition on anticompetitive uses of allowances.

The development of competitive power markets could be thwarted if, as we fear, utilities that hold the allowances hoard them, do not make them available to independent power, or make them available only at unreasonably high prices. Unless a real market for allowances develops in which independents can with reasonable certainty obtain needed allowances for new growth at reasonable prices, these bills could frustrate competitive power.

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[1] The National Independent Energy Producers is an association of independent firms that generate electricity for sale to utilities and develop co-generation and alternative energy projects for a variety of users.

II. CURRENT LEGISLATIVE STATUS

S. 1630, as reported from the Senate Environment and Public Works Committee, includes a provision setting aside a 2 percent federal reserve of allowances at a fixed price of $1,500/ton for independent power producers and others who may not have access to allowances. This provision is an important step toward ensuring that amendments to the Clean Air Act do not jeopardize competition in power markets.

However, it does not entirely resolve NIEP's concerns because the provision fails to provide for a sufficient number of reserve allowances, statutorily fixes a price for those allowances, and does not contain any mechanism to prohibit anticompetitive use of allowances by allowance holders.

By contrast, the House Subcommittee bill, H.R. 3030, does not provide for any type of set-aside reserve allowances; nor does it prohibit anticompetitive behavior.

III. THE PROPOSED SOLUTION

NIEP's proposed solution has two basic parts. (This proposed solution is described in more detail in the attached legislative specifications.) The first part would, effective on date of enactment, set aside reserve allowances to be made available promptly if at any time necessary allowances for new power generating facilities cannot be obtained at a reasonable price in the marketplace. The reserve system, however, should set aside at least 5 percent of the 8.9 million tons of allocated allowances (445,000 tons) as opposed to 2 percent set aside in S. 1630. A reserve of at least 445,000 tons is essential in light of new generating capacity needed and the broad range of entities that may be eligible to draw on these reserve allowances. (These eligible entities may include independents, municipalities, cooperatives, and conventional utilities that hold only few or no allowances.)

In NIEP's view, even a 450,000 ton reserve of allowances may not be sufficient to meet the demand for such allowances. Looking at the needs of the independent power sector alone, we estimate that 200,000-400,000 tons/year of SO_2 allowances may be required by the year 2000 to meet anticipated new capacity requirements. The Senate Environment and Public Works Committee report on the Clean Air Amendments estimates that "competitive independent power producers will be contributing 40 to 50 percent of the United States' new generating capacity in the next 10 years." Other eligible entities that may draw upon the reserve may include municipalities, cooperatives, and conventional clean or small utilities. Given this broad range of eligible participants in the reserve system and their anticipated new power production needs over the next 10-15 years, a set-aside of 178,000 tons simply is insufficient.

Of course, the adequacy of the reserve system depends in part upon how well the market works for trading in allowances. The second part of NIEP's proposal is designed to help ensure that a genuine and robust market for allowance trading does develop. The mere existence of an adequate reserve should help bring such a market into being. Establishing an adequate reserve would send a message to those who would be inclined to hoard allowances to defeat competition from independent power that this tactic will not work.

NIEP supports the establishment of an initial statutory price for purchase of reserve allowances. Reserve allowances prices should be high enough to dissuade potential applicants from preferentially seeking allowances from the reserve rather than in the market. Based on EPA's estimate that marginal cost of SO_2 control would range from $600-$800/ton, NIEP views $1,500/ton as an acceptable start-up (and fallback) price for reserve allowances.

However, in keeping with the philosophy of the bills, prices of reserve allowances should be revised periodically to reflect actual marginal cost of SO_2 emissions control. The revised price should be based on a statutorily set formula that would include, but not be limited to, annualized costs of both capital expenditures and operating expenses.

To demonstrate eligibility for reserve allowances, buyers should be required to show that they are not major holders of excess allowances, do not have the ability to create allowances, and are not speculators. They should also be required to show that allowances needed for the life of the plant are unavailable in the market at or below the price established for reserve allowances.

Finally, the agency designated to administer the reserve system should be authorized to mandate SO_2 controls and to float bonds and/or sell futures contracts to reimburse utilities required to implement such controls for their marginal capital and operating costs. This authority could be used to replenish the allowance reserve system if it becomes depleted. This authority could also be used to establish the price basis for the sale of reserve allowances using actual marginal cost of control data.

The second part of the NIEP proposal would add new language prohibiting utilities that are initially allocated allowances under the bill from using these allowances or other related means to frustrate competition in wholesale power markets. This part of the proposal would help ensure that independents and others wishing to purchase allowances could do so at nondiscriminatory prices, while promoting the market for allowance trading. See Attachment 1, part B, for a more detailed description of this proposal.

IV. JUSTIFICATION

NIEP believes the nation has much to gain from competition in power markets.* However, the proposed amendments to the Clean Air Act may unintentionally undermine this competition to the detriment of consumers.

The NIEP proposal attempts to ensure that the growth of competitive power is not harmed by either the failure to make allowances available in the market or by the discriminatory sale of allowances. The proposal provides a modest backstop remedy, a market of last resort, for those power producers who might otherwise be precluded from future growth opportunities.

The NIEP proposal is based on, and supports, the following principles:

- Clearly, a statutorily determined price for reserve allowances is preferable to an auction system that cannot provide certainty. Furthermore, a pricing system that reflects actual marginal cost of control is more desirable than a single legislatively fixed price.
- To promote the degree of certainty necessary for planning and financing new generation capacity during the 1990s, availability of adequate allowances at established, nondiscriminatory prices for the life of a new unit should be ensured.
- A cap on SO_2 emissions should remain so long as there are safeguards to prevent distortion or frustration of competitive power generation markets.

ATTACHMENT 1:

GROWTH ALLOWANCE FOR COMPETITIVE POWER: NIEP CLEAN AIR SPECIFICATIONS

A. STANDBY PROVISIONS TO ENSURE ALLOWANCE AVAILABILITY AT REASONABLE PRICE FOR NEW UNITS THAT DO NOT GET SIGNIFICANT INITIAL ALLOCATION OF ALLOWANCES

1. Provide for federal reserve of 5 percent of the 8.9 million tons of allowances allocated under Phase II (i.e., 445,000 tons) by issuing only 95 percent of the total number of allocated allowances to each affected unit. Reserve allowances would be available only as a contingency in the event that the market system envisaged by the bills fails to make available the necessary number of allowances for the necessary number of years to satisfy allowance requirements for a unit's anticipated useful life at or below the price to be established under spec. #2.

2. Provide that, within six months of enactment of the bill and at least every two years thereafter, a governmental agency designated by the President would determine a reasonable ceiling price based on the marginal cost of SO_2 control. The formula for determining the marginal cost of control would be specified in the statute. An initial statutory price ceiling of $1,500/ton of SO_2 would be prescribed by the bill and would apply in the event that any revised price is stayed or rendered invalid by a court of law. (Attachment 2 describes this price-setting mechanism.)

3. Upon a showing by the applicant at any time after the day of enactment that it meets eligibility requirements for a sale of allowances from the reserve, the designated agency would be required promptly to sell or guarantee to the applicant the necessary number of allowances for the new unit covering at a minimum all the years of its anticipated useful life at the price then in effect under spec. #2.

4. Eligibility requirements for a mandatory sale from the set-aside reserve should be established in the law (subject to agency authority to adopt additional eligibility requirements). The initial set of statutory eligibility conditions should be as follows:

   (a) The applicant must be an independent power producer or a utility without a significant initial allocation of allowances and without sufficient ability to create excess allowances to meet additional future power generation needs.

   (b) The applicant must be able to provide substantial evidence (e.g., the existence of a power purchase contract) of its intention to commence construction or expansion of one or more new steam electric units within three years after receipt of the necessary allowances.

(c) The applicant must have sought to buy the necessary allowances in the market and been unable to get them in sufficient quantity and duration at or below the operative ceiling price established under spec. #2, as demonstrated by advertisements in specified business publications and letters to prospective sellers.

(d) The applicant has notified the designated agency of this inability to secure the necessary allowances within this price range and that agency, after publishing notice in the Federal Register (within 30 days of receipt of an application), has not identified within 60 days of publication of that notice a willing seller of the necessary allowances at or below the price established under spec. #2.

(e) There are remaining allowances in the reserve that can meet part or all of the applicant's need.

5. In the event all reserve allowances are sold or guaranteed, the designated agency would be authorized to impose additional SO_2 controls on utilities that received significant initial allocations of SO_2 allowances. The agency would be authorized to float bonds or sell futures contracts for power supply to reimburse the utility for its marginal costs (capital and operating) of such controls. The agency would then be authorized to replenish the reserve with the excess allowances that result from applications of these controls. The agency would also be authorized to impose such controls as necessary to establish a real-world basis for establishing marginal control cost-based pricing for reserve allowances.

B. PROGRAM TO PROHIBIT ANTICOMPETITIVE USE OF ALLOWANCES

1. The responsibility for administering the anticompetitive program would be assigned to the President with a mandate for the President to delegate by order this program to the appropriate governmental entity within 180 days of enactment.

2. Provide as a condition of the state permit program that prior to the time a utility seeks to sell initially allocated allowances to an affiliate or to use those allowances to build its own new or expanded cost of service plant, the utility would be required to provide notice to the delegated governmental agency, state public utility commission, and the public requesting competitive bids for the allowances.

3. As a condition of the state permit program, sale of initially allocated allowances to affiliates of utilities other than through a competitive bidding process would be prohibited. The utility would be required to solicit and take bids for such allowances from any party proposing to provide electricity for customers within the service territory to be served by the affiliate. The President's designated agency and the state public utility commission (PUC) would be authorized to enforce the prior notice and allowance bid requirement and the prohibition on discriminatory sale of these allowances to affiliates. This agency and

the PUC would be authorized to obtain emergency, temporary, and permanent equitable relief (i.e., judicial temporary restraining orders and injunctions) to stop violations. Citizen suit authority should also be provided. (This prohibition would not apply to allowances that a utility has purchased.)

4. Similarly, as a condition of the state permit program, prior notice and request for competitive bids for such allowances would be required before a utility could use its initially allocated allowances to build a cost of service plant. The utility would be required to notify the delegated governmental agency, state public utility commission, and the public of its intent to use these assets to build new generation facilities. The utility would also be required to request competitive bids for these allowances before the utility could obtain requisite approvals to build the new or expanded facilities. The utility would be required to solicit and take bids from any party proposing to provide electricity for customers within the service territory to be served by the new or expanded cost of service plant.

5. The competitive bid process for these allowances would give others (independents and other utilities) the right to purchase these allowances if their sealed bids are higher than the sealed bid price of the initial allowance holding utility. If the initial allowance-holding utility wins the bid for SO_2 allowances, it would be required to list this price as its allocated price when it seeks to build its new cost of service plant. Again, the designated agency and the PUC would be authorized to enforce these requirements and the minimal authority necessary to ensure that these notice, request for bids, and sale/price allocation requirements are actually being observed. Citizen suit authority should also be provided. (This provision would apply only to initially allocated allowances, not to allowances that are subsequently purchased.)

6. Parties that are ineligible to participate in the reserve allowance program would be prohibited from forming subsidiary or affiliate entities to seek such reserve allowances and thereby stifle competition from potential competitors who may have to rely on the reserve system to obtain needed allowances.

This approach has several advantages. First, this system promotes creating a market for SO_2 allowance trading and helps prevent discriminatory or abusive use of allowances to stifle competition. Second, rate payers would benefit from sales of allowances through rebates or reduced electric rates. Third, governmental involvement to ensure proper functioning of this system would be minimal. The proof needed to demonstrate a violation is very specific as is the relief that an independent party would request.

ATTACHMENT 2:

NIEP PROPOSED PRICE-SETTING MECHANISM FOR SO_2 ALLOWANCES TO BE SOLD FROM RESERVE

1. An initial statutory price ceiling of $1,500/ton of SO_2 would be prescribed by the bill. This statutory price ceiling would apply until a revised price is determined and during any period the revised price ceiling is stayed or invalidated by any judicial actions.

2. At least every two years after enactment of the bill, the agency designated by the President would be required to determine the revised price, which could be higher or lower than $1,500/ton. The revised price would be based on the marginal cost of SO_2 control, as determined in accordance with a formula to be specified in the statute. The statutorily set formula would include, but not be limited to, annualized costs of both capital expenditures and operating expenses. Other elements of the price-setting mechanism would include the following:

   - The designated agency would obtain any necessary data to implement the formula by requiring affected facilities (in Phase I and Phase II) to report the costs of control and the amount of SO_2 removed using these control measures. The FERC Form 1, filed annually with FERC and state PUC, is a possible reporting vehicle. New account numbers under FERC's uniform system of accounts could be established for categories of operating costs, capital costs, and fuel costs.

   - The designated agency would be directed to promulgate a rule within 90 days of enactment specifying what information is to be reported and the mechanism (FERC or otherwise) for submitting this information. The designated agency would be directed by Congress to include, at a minimum, any information necessary to ensure that the formula could be implemented.

   - Finally, to ensure that the marginal cost of control determination is based on recent real-world data, the designated agency would be authorized to mandate SO_2 controls in limited, specified amounts and to float bonds or sell futures contracts to pay the marginal costs of such controls. These transactions could then be used to establish the price basis for the sale of reserve allowances. This authority could also be used to create additional allowances for the reserve system, if needed.

CMA
CHEMICAL MANUFACTURERS ASSOCIATION

Robert A. Roland
President

January 23, 1990

The Honorable Bennett Johnston
Committee on Energy and Natural Resources
136 Senate Hart Office Building
Washington, D.C. 20510-5424

Dear Chairman Johnston:

The Chemical Manufacturers Association (CMA) wishes to express its views on several cost-related aspects of the pending clean air legislation (S.1630). I request that these views be included in the record of the Committee's hearings on the energy implications of S.1630 to be held January 24 and 25, 1990.

CMA is a non-profit trade association whose member companies represent more than 90 percent of the productive capacity of basic industrial chemicals in the United States. CMA's interest in the energy cost-related aspects of the pending legislation results from the fact that the chemical industry is a major consumer of virtually all types of energy. In 1988 the industry consumed 5.4 quadrillion BTUs of energy -- the equivalent of 2.55 million barrels a day of crude oil -- as a fuel or source of power, and as a feedstock or raw material for industry processes. This represented about 19 percent of U.S. industrial energy consumption, and 6.8 percent of all energy consumed in the United States.

Overall, natural gas is the chemical industry's largest energy source, providing about one-third of its needs. Petroleum derivatives, i.e., liquified petroleum gas, naphthas, and gas oils account for about one-fourth of the total. Electricity -- produced from coal, oil, natural gas, hydro and nuclear sources, and some of which the chemical industry produces itself -- represents not quite one-fifth of the industry's consumption. Natural gas liquids, fuel oil, coal and coke also contribute to the industry's energy needs.

Adequate supplies of competitively priced energy are indispensable if the chemical industry is to maintain its ability to contribute to the country's economic growth, national security, export growth, and well-being. As noted above, the chemical industry is a major energy consumer. In addition, many chemical industry processes are energy-intensive. Although the industry continues to improve the efficiency of its use of energy, a reduction in the availability of energy supplies would inevitably result in a reduction in the industry's ability to produce the chemicals and related products our country and our overseas customers need.

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Equally important, as assured energy supply, is the price at which energy is available. The chemical industry operates in an increasingly competitive, global economy. CMA would like to emphasize to the Committee the strong export performance of the U.S. chemical industry, and its trade surplus in chemicals. Both U.S. exports and the surplus have increased substantially over the decade. Chemical exports grew from $12.6 billion in 1978 to the 1988 level of $32 billion. Our trade surplus grew from $6.1 billion in 1978 to its 1988 level of $12.4 billion.

The chemical industry is proud of this performance, but CMA believes it is important to recall that U.S. imports of chemical products have also increased over the decade, from $6.4 billion in 1978 to $19.9 billion in 1988. The annual growth rates of both imports and exports have varied considerably over this period. In some years exports have outperformed imports, but the reverse is also true. Although CMA can not predict the future, the rising import values mentioned above serve as a stern reminder of the intense competition the chemical industry faces in the global market -- within the United States and overseas.

The chemical industry is making every effort to maintain and improve its global competitiveness. It is aggressively responding to its customers' needs and striving to ensure the highest product quality. To be competitive, the industry's costs must be competitive with those of other countries' chemical industries. The industry is working vigorously to improve its cost competitiveness. But CMA would like to emphasize that competitively priced energy is an essential part of this effort. Therefore, CMA believes the United States should promote policies that increase the supply of all forms of energy. Simultaneously, CMA believes the United States should avoid policies which raise the cost of energy to the U.S. chemical industry relative to energy costs of our overseas competitors.

From the perspective of the above background, CMA would like to express its views on three issues in particular:

- the possible inclusion of industrial manufacturing units in the acid rain control provisions of S.1630;
- a possible fee, penalty or tax on SO_2 emissions; and,
- the mandated use of natural gas for environmental reasons.

CMA objects to the inclusion of industrial manufacturing units in the acid rain control provisions of S.1630. The inclusion of industrial boilers, cogeneration, and process units would be an inequitable and inefficient means of achieving emission reductions. Such an inclusion would place a disproportionate cost burden for acid rain controls on U.S. industry, over and above projected electricity rate increases.

CMA believes that the inclusion of manufacturers in a reduction program is economically inefficient and will restrict economic growth while achieving only minimal reductions. The small size of industrial units, the complexity of required controls, and the amount of reductions already achieved mean that additional reductions from industrial units will be extremely expensive -- perhaps three to four times the cost of similar reductions from larger utility units, substantially because of the scale factor. Further, to subject industrial cogeneration to emissions restrictions would create a disincentive to cogeneration and contradict important national energy goals: improved power generation, fuel efficiency, diversity of electric supply, and expansion of less expensive power production.

Industrial manufacturers will bear a major share of the costs of any proposal to reduce SO_2 emissions -- through significant electric utility rate increases. Additional source controls on manufacturing units will only impose further burdens on industry with minimal benefits, and should be avoided.

A tax, penalty or fee on SO_2 emissions has been suggested as a means of sharing the costs of reductions in SO_2 emissions. CMA opposes the application of such a fee to industrial sources. Using publicly available data, CMA has calculated that the cost to the chemical industry (SIC 28) of a $55/ton charge on process and fuel emissions would be approximately $43 million/year. In addition, the pro rata cost to the chemical industry of a $45/ton charge on electric utility SO_2 emissions would be approximately $39 million/year. This latter cost could be substantially greater if regulatory officials did not allow the pass-through to residential or commercial customers of their pro rata shares of the electric utilities' SO_2 emissions charges, so that more than a proportionate share was passed through to industry. None of the preceding costs, it must be emphasized, include the substantial costs of capital improvements needed to meet SO_2 emissions reductions envisaged in the pending legislation.

Given the intense international competitive pressures facing the U.S. chemical industry, the additional costs to the industry which would result from the proposed SO_2 emissions fee would inevitably diminish U.S. international competitiveness, to the detriment of U.S. production, employment, and exports. (At the same time, the chemical industry is facing significant new costs under the air toxics title of S.1630 -- costs which are projected to be far higher under S.1630 than would be the case under S.1490 (Administration bill).)

Acid rain legislation, as currently proposed, raises serious concerns about the impact this legislation may have on natural gas supply/demand. The imposition of an SO_2 emissions cap combined with the uncertainty surrounding the proposed tradeable allowance concept could lead to a limitation on the construction of new coal or oil based power units. Under these circumstances natural gas would generally be the fuel selected for new power plants. To the extent fuel flexibility is constrained, this legislation will have the effect of "mandating" natural gas as the fuel to be used in power production. This has the potential for higher natural gas prices and/or shortages, either of which would adversely affect the U.S. chemical industry's international competitiveness. The effects would also be felt by other industrial, commercial and residential natural gas customers. Because of these considerations, CMA believes that any SO_2 emissions cap and allowance trading system should be designed and implemented with sufficient flexibility and safeguards so that coal and oil remain viable options for use in future power production units, and "mandating" natural gas use is avoided.

Recognizing that natural gas demand has increased substantially over the past few years and that pending clean air legislation can only strengthen this trend, CMA is concerned that efforts to ensure a corresponding increase in supply may be inadequate. Without increased supply availability, gas can not fulfill its potential to ameliorate environmental problems. If supplies are available to meet rising demand, prices will remain competitive and market forces, in and of themselves, will promote the use of natural gas.

Responsible efforts to develop available natural gas resources must be encouraged if gas is to realize its potential in environmental solutions. Specifically, CMA supports responsible exploration and development of natural gas in environmentally sensitive areas.

CMA's concerns regarding natural gas are elaborated in the attached paper recently prepared by CMA, entitled "Comments of the Chemical Manufacturers Association; Natural Gas Supply and Artificial Demand". CMA requests that this paper also be made a part of the record of these hearings.

CMA appreciates the opportunity to express its views.

Sincerely,

Robert A. Roland
President

Attachment

Comments of the Chemical Manufacturers Association
Submitted to the Senate Committee on Energy and Natural Resources
Hearings on Energy Implications of S.1630, January 24-25, 1990

Natural Gas Supply and Artificial Demand

Proposals to promote the use of natural gas as a means of addressing this nation's environmental problems have been raised in recent policy discussions. It is argued that such action will improve environmental quality by substituting a cleaner burning fuel for other fossil fuels. Hand in hand with this argument is a perception that the U.S. resource base for natural gas is large, and that laws and regulations promoting natural gas consumption will resolve the problems associated with developing this resource base.

Increasing the supply of natural gas is a laudable goal, especially in the current environment where exploration activity remains low, proved reserves continue to decline and demand continues to grow. Policies that increase the supply of natural gas should be encouraged.

Policies that artificially promote the use of natural gas, however, would be counterproductive. Suggested policies of concern include mandating natural gas use and other non-market mechanisms that provide a bias for natural gas relative to other fuels.

This issue is of crucial interest to the Chemical Manufacturers Association (CMA). CMA is a nonprofit trade association whose member companies represent approximately 90 percent of the productive capacity of basic industrial chemicals in the United States and Canada. The U.S. chemical industry supplies a number of vital products, including those required for the manufacture of plastics, fertilizers, textiles, tires, paints, coatings, and a host of industrial and consumer goods. In 1988, the chemical industry employed about 1 million people domestically and had a positive trade balance of $12.4 billion dollars.

The U.S. chemical industry is highly energy intensive and relies on natural gas supplies for feedstock and fuel. The industry accounts for about 10 percent of total U.S. natural gas consumption and over 25 percent of industrial gas consumption, making it the nation's largest industrial natural gas user. Thus, access to adequate natural gas supplies at competitive costs is essential to the chemical industry's economic viability, and is a paramount objective for CMA member companies.

Current Natural Gas Reserves and U.S. Demand Patterns Indicate a Natural Gas Supply/Demand Imbalance.

. Current U.S. natural gas supplies give reason for caution as natural gas is discussed in an environmental context. Proved reserves in the lower 48 states have been declining at alarming rates in recent years. Proved reserves at the beginning of 1971 were about 260 trillion cubic feet, as compared to 154 trillion cubic feet at the beginning of 1988. This represents a 41 percent decline over a 17-year period. (Even Canadian reserves, the source of most imported natural gas into the United States, are declining according to a recent Canadian Petroleum Association report.) CMA believes efforts to reverse the decline in U.S. reserves are badly needed to ensure adequate future natural gas supplies to meet current and projected needs.

Since 1981, the number of producing gas wells completed has also been on the decline. Producing wells completed in 1987 totalled only 7,200, less than half the 1981 level of 18,400. Completed exploratory wells were 21 percent of completed producing wells in 1974, but fell to only 12 percent by 1984, and have remained virtually constant at this level for the last five years.

As a result, additions to proved reserves in 1987 for the top forty U.S. gas reserve-holding companies amounted to only 70% of production. Although some reports have 1988 replacement levels as high as 130% it must be noted that much of this replacement resulted from a high level of "revisions", and that new discoveries during 1988 represented only about 60% of production.

Meanwhile, U.S. natural gas consumption has been on the increase. Over the past three years demand rose 14.2 percent, climbing to 18.5 trillion cubic feet during 1988 as compared to the 1986 low of 16.2 trillion cubic feet. Consumption of natural gas increased more than any other fuel between 1987 and 1988 (5 percent), and if the outlook for the U.S. economy remains strong, demand is likely to continue to rise.

In fact, demand is increasing more rapidly than production. According to the latest Energy Information Administration figures, 1988 production increased only 0.6 percent to 16.6 trillion cubic feet, although consumption was considerably higher at 18.5 trillion cubic feet. This difference, met largely via Canadian imports, strongly suggests a need to increase U.S. natural gas production. Increased natural gas production not only would serve to better maintain pace with rising demand, but also would result in a corresponding increase in the production of natural gas liquids, an important source of feedstock for the U.S. chemical industry and the precursor to vast numbers of consumer goods.

Energy Policies Should Include Consideration of Their Environmental Impact, But Consumer Choices Should Not Be Dictated.

It is widely understood that some energy management practices may have an adverse effect on the environment. A range of options are available to address these potential impacts, including such measures as improved efficiency and conservation, development of new technologies, and fuel switching. CMA believes that, as these broad areas are pursued with energy and environmental goals in mind, government policies should not dictate the choices available to consumers. Rather, the selection of specific options should be based on the merits of each option as determined in the marketplace.

Increased natural gas use is one option that should be considered on its own merits vis-a-vis other energy options. The marketplace should determine whether this is a preferred option, however, because any artificial promotion or mandated natural gas use could have a negative effect: tightening supply, raising prices, limiting interfuel competition, reducing available capacity of existing distribution systems, and damaging U.S. industrial competitiveness in world markets. Energy intensive industries such as petrochemical and related derivative producers simply cannot compete effectively in world markets without competitive energy costs.

Natural Gas Supply Should Be Promoted So That Natural Gas Can Compete With Other Fuels On Its Own Merits.

Recognizing that the use of natural gas in place of other fossil fuels could be an option for addressing environmental concerns, CMA supports actions which encourage increased supply and availability of natural gas. Many steps have already been taken which should have a positive impact on supply. These include open-access natural gas transportation, access to Canadian imports, and decontrol of wellhead natural gas prices. Further actions to increase availability and access to supplies, such as pipeline rate reform and responsible exploration and production in environmentally sensitive areas, also merit consideration. Actions and policies which lead toward increased supply of natural gas in and of themselves promote, through market forces, use of natural gas as an alternate to other fuels.

Mandated use of natural gas to address environmental concerns should be avoided. Mandating natural gas use will create distortions in the marketplace and in natural gas distribution systems, and will adversely affect industrial competitiveness. Finally, mandated use of natural gas is unwarranted. By opening access to transportation, encouraging additional supplies, and encouraging competition, natural gas use will increase. A market driven approach is the most efficient way of achieving increased natural gas utilization for the benefit of both the environment and the economy.

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10/27/89

Before the Committee on Energy and Natural Resources
United States Senate
Hearing on S. 1630
Clean Air Act Amendments of 1989

Testimony of Carl S. Whillock
President and Chief Executive Officer
Arkansas Electric Cooperative Corporation

January 24, 1990

Summary of Testimony of Carl S. Whillock
President and CEO of Arkansas Electric Cooperative Corp. (AECC)

- As one of the cleanest electric utilities in the United States, AECC applauds both the President and Congress for the commitment to deal with our nation's acid rain problem.

- But the Senate bill penalizes utilities that have already proven their commitment to clean air. Although we have always operated very clean units, the bill will force us to make large capital outlays to cut our emissions even more.

  - By requiring us to reduce our SO2 emissions even more, and to levels well below those required of the dirty utilities, the legislation will force us to install expensive scrubbers on already clean units.

  - We are in fact penalized for being clean. By burning clean coal (two thirds of the cost of which is transportation from Wyoming) our units already operate at emission levels substantially below the new levels the legislation sets for the dirty units.

  - The calculation of our allowed emissions is based on our actual 1985 emissions. But 1985 was a unique year in that we were able to secure super-clean coal because we tapped an extraordinarily clean seam. Our 1985 emission rates cannot be consistently replicated.

- The allowance system will make it extremely difficult for AECC to install new generating units after January 1, 2000.

  - The bill does not make reasonable provision for clean utilities to grow to meet new demand.

  - It will be difficult to purchase allowances from other utilities. Their regulators may even prohibit them from selling unused allowances.

  - It will be very hard for an already clean utility to save sufficient allowances by reducing emissions from existing units well below the new stringent levels set by the legislation (in effect, "over cleaning" such units).

- AECC is supporting 2 kinds of environmentally-sound and fair changes in the legislation:

  - We support a plan that has been proposed by Entergy Corporation (the parent of AP&L) to base the calculation for clean coal units on an emission rate not to exceed 1.0 lbs/mmBtu (still below the 1.2 lbs standard that will be required of the dirty units) and to limit oil and gas units to a rate of 0.4 lbs/mmBtu.

  - We are working with others of similar interest to craft a modification to ensure that clean utilities will be able to install needed units after the year 2000.

Testimony of Carl S. Whillock
President and Chief Executive Officer
Arkansas Electric Cooperative Corporation

I. Introduction.

Distinguished members of the Committee on Energy and Natural Resources, I welcome this opportunity to comment on S. 1630, the Clean Air Act Amendments of 1989, and in particular on the acid deposition control provisions of Title IV of the bill.

At the outset, let me make clear my purposes here today. As one of the cleanest electric utilities in the nation, Arkansas Electric Cooperative Corporation (AECC) applauds both the President and Congress for the commitment to dealing with the problem of acid rain and air pollution. We support the enactment of legislation substantially curtailing the emissions of sulfur dioxide (SO2) and oxides of nitrogen (NOx). AECC's units have consistently achieved low emissions levels and will continue to do so in the future.

We are deeply concerned about the legislation, however, for two reasons.

> First, although our coal plants have consistently operated at emissions levels well below the lowest of the new standards that will be required of the dirty units, we get no credit for being clean and in fact are penalized for it. Although we burn very clean low-sulfur coal, we will be forced to install expensive scrubbers on our coal units to make them even cleaner. Our clean oil and gas units will not earn allowances and generally will be held to a zero emissions level for the life of the units. This means they must burn gas only.
>
> Second, the allowance system creates severe problems for already clean utilities that need to add generating capacity after the year 2000. It will be

extremely difficult for an already clean utility to earn extra allowances, and the industry is virtually unanimous in its belief that allowances will not be readily available for purchase.

We strongly believe the legislation should be improved by amendments to allow clean utilities both to operate their units within environmentally-sound limits and to add needed capacity after the year 2000.

II. AECC's Operations

Arkansas Electric Cooperative Corporation is the supplier of electric power for seventeen of Arkansas' electric distribution cooperatives, which in turn serve more than 300,000 homes, farms, businesses and industries covering more than 60% of the state's land area. Our total capacity, consisting of oil and gas, clean coal, and hydroelectric units, is 1890 MWe.

We own portions of three clean coal-fired electric stations:

- 35% of the Independence Station (1678 MWe) at Newark, Arkansas;
- 35% of the White Bluff Station (1659 MWe) at Redfield, Arkansas; and
- 50% of the Flint Creek Station (480 MWe) at Gentry, Arkansas.

These facilities consistently operate at levels well below the 1.2 lbs/mmBtu SO2 emission level, the new standard that most units will have to meet after January 1, 2000. The Independence units, for example, are operating at roughly 0.5 lbs/mmBtu, and in 1985 Independence operated at 0.45 lbs/mmBtu making it the cleanest unscrubbed coal plant in the nation. Our units burn clean Wyoming coal, two thirds of the cost of which is transportation to Arkansas. Our plans call for the installation of a new 400 MWe coal unit in the year 2004.

AECC also owns three oil and gas units:

- Fitzhugh Station (59 MWe) at Ozark, Arkansas;
- Bailey Station (122 MWe) at Augusta, Arkansas;
- McClellan Station (134 MWe) at Camden, Arkansas;

Finally, AECC has made a commitment to developing clean hydropower on the Arkansas River. The Clyde T. Ellis Generating Station (17 MWe) at Lock & Dam #13 near Barling went into commercial operation in December 1988. In the near future we will begin construction on a similar plant at Lock & Dam #9 near Morrilton, and we hold licenses on two other sites on the Arkansas River -- Lock & Dam #3 near Grady, and #2 near Arkansas Post.

III. Title IV of S. 1630.

Title IV of S. 1630 seeks to control acid rain by achieving substantial reductions in SO2 and NOx emissions. Since SO2 and NOx come from the burning of fossil fuels (coal and oil, primarily) the legislation targets the utility industry for reductions. A high percentage of the overall emissions come from the older oil and coal burning electric units in the Midwest.

Under the legislation, and in accordance with a compromise reached among President Bush and Senators Baucus and Mitchell, SO2 emissions will be reduced by 10 million tons by January 1, 2000 and thereafter emissions will be capped at the year 2000 level.

Although aspects of the acid rain title are complex, the 4 most important points are as follows:

1. In Stage I, the 107 dirtiest generating plants must reduce their SO2 emissions down to 2.5 lbs/mmBtu by 1995 (sec. 404(a)).

2. In Stage II, virtually all generating plants (including the 107 Stage I plants) must reduce SO2 emissions down to 1.2 lbs/mmBtu by the year 2000, and never emit in excess of that level (sec. 405).

3. The achieved reductions are kept in place by a system of so-called allowances. An allowance is an authorization to emit SO2 (and NOx) at a certain level. Stage I utilities are given allowances to emit at the 2.5 level from 1995-2000, and in stage II the allowances generally authorize emissions at not to exceed 1.2 lbs/mmBtu.

- After the year 2000, virtually all electric generating units that emit SO2 must own allowances matching such emissions. If a utility needs to add new generating capacity, it must either purchase or earn allowances sufficient to cover the emissions of the new unit.

- Purchasing allowances. Once the dirtiest utilities cut their emissions, they will have allowances they could sell, but the legislation has no mechanism to force such sales. Utility regulators in the Midwest may prohibit their utilities from selling allowances, or the utilities may hoard allowances for competitive reasons.

- **Earning allowances.** Since utilities will need allowances to operate existing units, the only way to earn the allowances needed to operate a new unit is to reduce emissions on existing units even lower than the level required by the legislation. For example, if a utility subject to the 1.2 standard scrubs way down to, say, 0.2 lbs/mmBtu, it has saved 1.0 lbs/mmBtu worth of allowances that can be used to operate a new unit.

4. Clean units -- both oil and gas, and coal-fired -- such as AECC's (already well below 1.2 lbs/mmBtu) are held to an even stricter Stage II standard based on our 1985 emissions (sec. 405(d) and (h)). In other words, even though our plants already have very low emissions levels, we must ratchet them down even more to comply with a legislative formula based on our actual 1985 emissions rates.

III. The 2 Problems Created for AECC.

First, the legislation will force us to install expensive scrubbers just to operate our already clean units. The estimated cost of a scrubber on one of our units is $250 million. Although our ratepayers have already borne the expense of installing and operating clean units with low emissions, they get no credit for being clean.

- As described earlier, AECC is a co-owner of the White Bluff and Independence coal units (with Arkansas Power & Light and 4 Arkansas cities). We are a co-owner of the Flint Creek coal unit along with SWEPCO. These units have always operated at well below the 1.2 lbs/mmBtu standard that will be required for the dirty plants in other states, but the legislation imposes a more stringent standard for us based on our 1985 emissions.

- 1985 was a unique year in that we were able to secure super clean coal for our coal fired units. For example, the Independence Electric Station is one of the very cleanest unscrubbed coal units in the nation. Its 1985 SO2 emission rate was 0.45 lbs/mmBtu, and since then has averaged 0.5 lbs. The emission rate of our Flint Creek Plant is 0.8 lbs/mmBtu, but was 0.59 lbs 1985.

  - Because 1985 emissions will be impossible to replicate consistently, we will be forced to install expensive scrubbers on these clean units. For us, the cost of scrubbers will be several thousands of dollars per ton of reduced emissions.

  - In essence, clean units get no credit for being clean and are penalized for having already expended the capital to achieve cleaner air.

- With respect to our three oil and gas-fired units, the bill limits them to their actual 1985 emission rate (sec. 405(h)). The problem is that since we burned only gas in 1985, our actual 1985 emission rate for these plants was zero (natural gas does not emit SO2). Thus, these plants must forever burn gas in order to meet a zero emission rate.

Second, the allowance system will make it extremely difficult for us to install new generating units after the year 2000.

- As pointed out earlier, a utility wishing to add new generating capacity after the year 2000 must purchase or earn allowances for that capacity. Because the legislation holds us to such stringent emissions standards, we will be unable to earn sufficient allowances for new capacity by "over cleaning" (reducing emissions well below the new stringent standards) our existing clean units. And, we and the electric utility industry as a whole are of the opinion that utilities with extra allowances will not generally be willing to sell them.

- AECC has plans to install a new 400 MWe unit by the year 2004, and we genuinely do not believe that allowances will be readily available for that unit.

IV. Proposed Solutions

AECC is supporting a plan that has been offered by Entergy Corporation (the parent of AP&L). This plan is emissions neutral when compared to the current Senate bill. It would base the calculation for clean coal units on an emission rate not to exceed 1.0 lbs/mmBtu. Also, the plan would limit oil and gas units to an emission rate of 0.4 lbs/mmBtu. This plan, which is described in much greater detail by the statement of Entergy Corporation also submitted for the hearing record this date, would at least allow us to operate our units without substantial additional costs.

AECC is also urging that a solution be found that will allow clean utilities to add new generating capacity after the year 2000. While it is certainly well intentioned, we do not believe that the allowance system as currently crafted is workable. We are working with others to find an environmentally sound solution to this problem, and we urge the members of this committee to support a reasonable change that accomplishes this goal.

In conclusion, AECC supports effective acid rain legislation, but it should be amended so it does not penalize the ratepayers of clean utilities. We urge the Committee on Energy and Natural Resources, and the Senate as a whole, to work for the enactment of legislation that will clean up the environment without imposing unreasonable costs and burdens on clean electric utilities.

COMMENTS OF ENTERGY CORPORATION

BEFORE THE

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

HEARING ON THE

"ENERGY POLICY IMPLICATIONS OF SENATE BILL S. 1630"

JANUARY 24 AND 25, 1990

SUMMARY OF COMMENTS OF ENTERGY CORPORATION BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE HEARINGS ON THE "ENERGY POLICY IMPLICATIONS OF SENATE BILL S. 1630" JANUARY 24 AND 25, 1990

Entergy Corporation supports the reduction goals of 10 million tons of SO_2 as expressed in S. 1630, but believes S. 1630 should be amended to provide additional flexibility to utilities that own and operate clean coal units and utilities that were heavily dependent on natural gas for generation in 1985.

I. Clean Coal Units. Coal units with emission rates below 1.2 lbs/mmbtu in 1985 will receive allowances based on either of two formulas:

1. The product of the unit's average annual fuel consumption rate at a capacity factor of 65% times actual 1985 emission rate, divided by 2000; or

2. The product of the unit's actual average annual fuel consumption rate between 1985 and 1987 ("baseline") times the lower of 1.0 lbs/mmBtu or the federally approved emissions rate, divided by 2000.

II. Low Emission Oil and Gas Units. Oil and gas units with emission rates below 0.4 lbs/mmBtu will receive no allowances, but will be permitted to operate an at annual average emission rate of up to 0.4 lbs/mmBtu.

III. NOX Standards. S. 1630 should be amended to restore the language in the administration's bill regarding reduction of NOX. Rather than mandating an emission rate for NOX of 0.45 and 0.5 lbs/mmBtu, the reductions should be achieved through the economic use of low NOX burners in power plants.

IV. Air-toxics. Utility sources should not be included in the provisions aimed at concentrated sources of air-toxic emissions. S. 1630 should be amended to include the administration's proposal to require EPA to do a three year risk assessment study of utility sources prior to imposing the Maximum Achievable Control Technology standards.

COMMENTS OF ENTERGY CORPORATION
BEFORE THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
HEARINGS ON THE
"ENERGY POLICY IMPLICATIONS OF SENATE BILL S. 1630"
JANUARY 24 AND 25, 1990

I. INTRODUCTION

Entergy Corporation is a public utility holding company that owns Arkansas Power & Light Company, Louisiana Power & Light Company/New Orleans Public Service Inc. and Mississippi Power & Light Company. Entergy Corporation's emissions of SO_2 are among the lowest in the nation. It serves over 1.5 million residential, commercial and industrial customers with a diverse generation mix of natural gas, oil, and coal, as well as nuclear power. All of Entergy's facilities have annual emission rates well below the 1.2 lbs/mmBtu level that will be required of most facilities under S. 1630.

Entergy Corporation has long been committed to environmental quality, and it continues to pursue the important objective of clean air. In the past 15 years Entergy has invested billions to construct generating facilities that produce a minimum of SO_2 emissions. As currently drafted, Title IV of S. 1630 would penalize utilities such as Entergy for having done voluntarily what other utilities only now are being forced to do: reduce annual SO_2 emissions to 1.2 lbs/mmBtu or less.

Entergy Corporation commends the Senate Energy and Natural Resources Committee for holding hearings on S. 1630. S. 1630 is a landmark piece of legislation designed to dramatically reduce the emissions causing acid precipitation.. The Senate's objectives in reducing SO_2 emissions are admirable and achievable. Entergy Corporation believes that Congress must act to control such emissions to avoid harm to our lakes, streams, forests and agricultural industry.

However, environmental policy cannot be made in a vacuum, without consideration to the impact on the nation's energy policy. Title IV of S. 1630 addresses and controls every fossil fueled electric generating unit in the nation and, according to EPA projections, will produce a 10 million ton reduction in SO_2 emissions. While that objective may be appropriate to accomplish a reduction in acid precipitation, the objective must be assessed also in terms of its impact on electric utility costs and reliability.

If enacted in its current form, the bill will have a dramatic impact on the electric industry. Estimates of the costs of complying with the bill range from $20 to $100 billion annually. Those costs will necessarily be translated into higher electric rates. When the bill is fully implemented and all new capacity must obtain emissions offsets, some utility experts predict shortages in capacity and supply. If the utility industry cannot construct new capacity, there will be an ever increasing risk of brown outs or black outs.

Entergy Corporation believes Title III of S. 1630 is an improvement over the administration's original proposal on acid rain. Nonetheless, S. 1630 contains some critical flaws that must be corrected to avoid inequitable and uneconomic results. Entergy Corporation submits these comments to bring these flaws to your attention in hopes of helping to make S. 1630 a better clean air bill: one that permanently reduces precursors of acid rain but accomplishes that objective efficiently and equitably, with least cost to the electricity consumers of America.

II. SUMMARY OF ENTERGY CORPORATION POSITION

From Entergy Corporation's perspective, S. 1630 could be vastly improved with relatively minor changes. First, S. 1630 should be amended to avoid unnecessary and unproductive restrictions on coal facilities that already are very clean and that already have reduced emissions to well below 1.2 lbs/mmBtu. Second, the bill should be altered to provide more flexibility to utilities that relied heavily on natural gas for generation in 1985. Third, S. 1630 should be amended to reduce the penalty it imposes on utilities that achieved low emission rates well before this bill was introduced, either through use of clean fuel sources or investment in emissions abatement equipment. Fourth, the emission rate standards imposed by S. 1630 should be altered in favor of a cost-effective, technology based standard. In particular, S. 1630 should be amended to require reductions that can be achieved through use of low NOX burner technology. Finally, S. 1630 should be amended to reflect the Administration's proposal regarding regulation of air toxics. Like the Administration's bill, S. 1630 should include a three year study of electric utility emissions to determine the extent, concentration and dispersion of air toxic emissions by electric generating facilities, to allow a well based determination of the risk posed by emissions of air toxics from utility sources.

III. AMENDING SECTION 405 OF S. 1630 TO MAKE A FAIRER BILL

Section 405 of S. 1630 sets the standards for Phase II of acid rain reductions. That section sets emissions standards for seven (7) classes of generating units: from the large dirty coal units to the ultra clean gas-fired generating units. Two of the provisions in Section 405 dealing with clean coal facilities and oil/gas generating units impose severe and unnecessary restraints on generating units that already are much cleaner than would be required of most units under the bill.

Those two subsections will achieve insignificant additional reductions in emissions, but will cost the rate payers of the utilities that own those units millions, perhaps billions, of dollars. The subsections also send wrong and irrational policy signals to utilities: namely, do not clean up until Congress forces you or it will cost you more.

Entergy Corporation proposes that these two subsections be amended to avoid penalizing clean utilities. The proposal would reduce the costs of the bill tremendously, yet it would result in a negligible increase in emissions.

A. Coal Facilities With Low Emissions Rates

Perhaps the most troublesome provision of Title IV is section 405(d), which imposes arbitrary and punitive limits on very clean coal fired units. Under the present bill, pursuant to subsection 405(d), utilities that own coal units with SO_2 emission rates below 1.2 lbs/mmBtu will receive allowances equal to 120% of their fuel consumption between 1985 and 1987 (defined as the unit's "baseline") times the 1985 emissions rate. The rationale behind that formula is that these units generally are new and much cleaner than most of the coal units in the country. As a result, the Environmental Protection Agency ("EPA") made the assumption that utilities, in response to this bill, will utilize the units more than they had in the past. S. 1630 gives these units allowances based on 120% of their baseline to account for anticipated increased utilization of the cleaner units in response to the bill.

The problem with this subsection is twofold. If a clean coal unit had either an exceptionally low emissions rate in 1985, or low utilization rates between 1985 and 1987, the unit will receive far fewer allowances than are necessary to operate the unit at the level for which it was designed. As a result, the utility will be severely constrained in operating that unit.

Entergy Corporation presents a good example of how this provision penalizes the clean utilities. Arkansas Power & Light has four coal units, each of which has emissions rates well below the 1.2 lbs/mmBtu level required for the dirty units around the country. At two of the units, Independence Numbers One and Two, the emission rates were approximately 0.45 lbs/mmBtu, the lowest of any unscrubbed coal unit in the country in 1985.

Entergy Corporation cannot continue to obtain coal of such quality to ensure that it can achieve such low emissions rates. If Entergy receives allowances based on such a low rate, then despite its investment in state of the art coal units and long term contracts for exceptionally clean coal, Entergy will be forced to either 1) scrub one or more of its clean coal units; 2) purchase allowances (assuming they are available) from utilities that own dirty coal units, which can be more cheaply scrubbed; or 3) operate the units less frequently, although they are among the most efficient coal units in the nation.

These options are simply not economically, environmentally or equitably justifiable. If Entergy installs a scrubber on just one of its units, it will cost Entergy rate payers approximately $250 million. If Entergy opts, instead, to purchase the allowances necessary to operate its units optimally, it will cost the rate payers $30 million annually, or approximately $400 million over the life of the units.[1] The final option will require Entergy to stop operating these highly efficient base load units once the allowances are used and run much more expensive natural gas generating units.

The inequity of imposing the strict limitations is seen in the economic impact on the rate payers of Arkansas Power & Light, Louisiana Power & Light and Mississippi Power & Light. Entergy serves 200 of the poorest counties in the nation located in Arkansas, Louisiana and Mississippi. Entergy also has some of the highest electric rates in the country, in part because of its efforts to ensure the cleanest possible generation of electricity. A $250 million to $400 million increase in electricity rates to pay for scrubbers or allowances from wealthier neighbor states, is an unreasonable and unfair burden to place on already overburdened ratepayers, especially given the fact that only minimal reductions in SO_2 emissions would be accomplished.

This penalizes rather than rewards clean utilities and sends the incongruous policy signal that utilities should not attempt to undertake measures to clean up their systems before Congress requires it. This bill tells utilities such as Entergy that, although they are cleaner than will be required of dirtier utilities, they must spend still more to achieve further reductions.

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[1] Based on the price from EPA as set forth in S. 1630 in section 403(a)(C). The cost still would be in excess of $15 million annually based on EPA's current, speculative estimation of the market price of allowances in 2010.

There is simply no cost effective way for clean utilities to comply with the current bill. Compared to the cost imposed on Entergy to meet the requirements of subsection 405(d) and still run its facilities efficiently, the reduction in SO_2 emissions produced by subsection 405(d) is minuscule.

B. Oil and Gas Units

Another problem area of Title IV is the subsection dealing with predominantly gas-fired units. Subsection 405(h) of S. 1630 applies to oil and gas units. Its effect is to limit oil and gas units to the 1985 emissions rate if the unit does not burn at least 10% oil annually. If a utility had ready access to natural gas in 1985, subsection 405(h) forces the utility to continue burning only natural gas, with no option to burn oil, except in emergencies, and then only after approval by the EPA. The units affected by subsection (h) receive no allowances and must maintain an emissions rate, effectively, of zero.

The effect of subsection 405(h) on Entergy Corporation is to prohibit it from switching from natural gas to oil except in the event of the most extreme shortages of natural gas. Entergy will become captive to the natural gas suppliers for all of its oil and gas fired units. By making these units captive to natural gas, the price of natural gas will certainly be much higher. With Entergy having no ability to negotiate with gas suppliers, and the electricity consumers of Louisiana, Arkansas and Mississippi will pay the price: an estimated annual increase of $50 to $75 million.

This will not only create inefficiencies, but it will threaten Entergy's ability to ensure reliable electric service whenever natural gas is in short supply.

Finally, subsection (h) has dire long-term consequences for utilities that relied heavily on natural gas in 1985. These utilities will have no ability to construct any future capacity that is not wholly dependent on natural gas without paying dearly for allowances. As discussed above, because units subject to subsection (h) are not subject to an annual tonnage limitation, they are not considered "affected units" under subsection 405(a) of S. 1630 and, as such, they receive no allowances. As a consequence, when these units ultimately are retired, the utility will have no allowances to use for new capacity. The utility will be forced to either replace that capacity with natural gas units or buy allowances from the dirty utilities.

That imposition blatantly discriminates against units that relied heavily on natural gas with oil as an alternative fuel. Other utilities receive allowances for existing units so that, when the unit retires, some allowances will be available for replacement capacity. Although new capacity will have to be very clean to operate fully with the limited allowances, there are, at least, some allowances available within the utility's system. Natural gas/oil dependent utilities will have no allowances for any replacement capacity.

Entergy was unfortunate enough in 1985 to have access to reliable and inexpensive supplies of natural gas. Because Entergy relied almost exclusively on natural gas to run its gas/oil generating plants in 1985, these units produced very low SO_2 emissions and will receive no allowances under the bill. Entergy believes that providing no allowances and limiting the emissions rate to near zero is improper and penalizes the utilities that are the cleanest.

C. NOX Emissions Standards

Under the current version of S. 1630, coal fired units will be required to achieve an emission rate for NOX of either 0.45 or 0.50 lbs/mmBtu, depending on the type of boiler involved. These standards are arbitrary and economically unrealistic. There is a cost effective means of reducing NOX emissions through the use of low NOX burner technology. Installing low NOX burners in coal units is effective in reducing NOX emissions, although it cannot always ensure an emission rate as low a prescribed by § 406 of S. 1630.

Although the difference in the emissions rates required by § 406 and those achievable by use of low NOX burners is not significant (probably about 0.15 lbs/mmBtu), many coal units would be required to install scrubber technology to comply with § 406. The administration has proposed requiring such units to install low NOX burners to achieve a reduction in NOX emissions and Entergy proposes that S. 1630 be amended to reflect that standard.

D. **Air Toxics**

A third and very important element of S. 1630 that could be more costly than all of the acid rain provisions is Title III, which deals with so-called "air toxics." Under that title, a source that emits during one year 10 tons of any one identified air toxic, or a total of 25 tons of all identified air toxics, must install control technology to reduce the emissions. For electric utilities, the very low aggregate total, as well as the single element total, is extremely constraining.

The problem with the provision is that it does not account for concentrations of the identified air toxics. For an electric utility that utilizes coal in a baseline unit, it is a near certainty that the aggregate level will be reached. A typical base line coal unit would consume approximately two to three million tons of coal annually. Although there are only trace amounts of metals and other elements identified in Title III as toxic in the coal, when the facility burns three million tons of coal even trace amounts can accumulate to twenty five tons annually.

The Administration bill, S. 1490, identified utility sources as a potential source of dangerous levels of air toxics and would require that the sources be monitored and studied for a three year period to allow the EPA to assess the risks associated with those sources, rather than imposing control requirements on the sources with little understanding of the risk posed by the sources. Entergy proposes that the Administration's proposal on air toxics be incorporated into S. 1630.

IV. PROPOSED SOLUTION

Entergy Corporation proposes amending S. 1630 to provide flexibility to the clean utilities in the country, without increasing emissions or the allowances. The amendment generally reflects the structure adopted in S. 1630, which deals with each class of unit individually.

The proposal allows utilities with clean coal units to select between two options. The utility could receive allowances based on the formula similar to the one currently in S. 1630, or based on the product of actual baseline times an emissions rate of 1.0 lbs/mmBtu or a federally approved emissions limitation, whichever is lower. In addition, the proposed language addresses the dual fired oil-and gas problem while keeping the very clean oil and gas fired units out of the allowances system entirely. The enclosed language limits dual fired facilities to an annual emission rate of 0.4 lbs/mmBtu, but offers no allowances for such a rate.

It is important to recognize that, because the oil and gas fired units will not receive allowances, the emission limitation of 0.4 lbs/mmBtu does not translate into emissions equal to 0.4 lbs/mmBtu. Rather, there will be only the potential for emissions, which will be realized only if natural gas is unavailable or becomes very expensive. It also is noteworthy that many such units are subject to much more stringent state-imposed limitations than 0.4 lbs/mmBtu.

The language below provides a more equitable treatment of all units, without increasing the total emissions allowed under the bill.

> "(d) Coal-fired Units Below 1.20 lbs/mmBtu. -- After January 1, 2000, it shall be unlawful for any coal-fired unit with an actual 1985 emission rate less than 1.20 lbs/mmBtu to exceed an annual tonnage emission limitation equal to one of the following:
>
> > 1) the product of the unit's average annual fuel consumption rate based on a capacity factor of 65% multiplied by its actual 1985 emission rate, divided by 2000; or
> >
> > 2) the unit's actual baseline multiplied by the lower of 1.0 lbs/mmBtu or the federally approved emissions rate, divided by 2000.
>
> Each utility must declare by December 31, 1999, which option it is selecting for application to its coal units and the selected option shall be applicable to all units owned by the utility within a state.

Regarding Subsection (h), which limits the very clean oil and gas units to 1985 emission rates, Entergy proposes the following language:

> **"(h) Oil and Gas-fired Units Less Than 0.4 lbs/mmBtu and Less Than 10% Oil. -- After January 1, 2000, it shall be unlawful for any oil and gas-fired unit with an actual 1985 emission rate of less than 0.4 lbs/mmBtu to exceed on an annual basis an emission rate of 0.4 lbs/mmBtu or its federally approved emission limitation, whichever is lower. Upon retirement of an existing unit under this subparagraph, the Administrator may, in his sole discretion, impose a more stringent emissions rate limitation on any replacement capacity.**

A. Discussion of Proposed Amendment for Clean Coal Units

The proposed amendment is designed to provide flexibility to utilities that own the cleanest coal units in the country. It will allow these utilities to maximize use of these clean facilities without penalizing them for having achieved low emission rates prior to this bill.

Subsection (d)(1) would provide allowances equal to the fuel consumption rate of a unit at a 65% capacity factor rather than 120% of baseline as in the current version of § 405(d). That provision reflects the assumption made by EPA in deriving its estimation of the 10 million ton reduction in emissions and would have the same emissions impact as the current version of subsection 405(d). By changing subsection (d) to calculate allowances on a 65% capacity factor, units that had abnormally low utilization in the baseline years will not be penalized.

Similarly, adding subsection (d)(2) to offer the option of calculating allowances based on actual baseline (rather than 120% of baseline) and an emissions rate of 1.0 or the state permit limit, utilities that had abnormally low emission rates will not be penalized.

It is critical to recognize that subsection (d)(1) still imposes limits on these very clean units that are more stringent that any limits imposed on far dirtier units. Furthermore, it treats these clean units much like the bill treats units under subsection (g). Subsection (g) addresses units that came on line between 1985 and the date of enactment of this bill. Those units are subject to the exact same existing regulations as the clean units the amendment seeks to help. There is no difference between these units, except they came on line before 1985, and there is no justification for imposing much more stringent limitations on units simply because they came on line prior to 1985.

B. Proposal Regarding Gas Dependent Utilities

Entergy also proposes that subsection (h) of § 405 be amended to provide some relief for utilities that relied heavily on natural gas in 1985. These very clean units must be given some flexibility to operate normally, which entails the ability to occasionally exceed the emission rate permitted by the bill. These units should be given the right to achieve an annual emission rate of up to 0.4 lbs/mmBtu, but receive no allowances.

By providing that minimum flexibility, utilities will be able to negotiate effectively with gas suppliers without being captive purchasers. The utility also will not be faced with extreme reliability problems in the event of natural gas shortages. And the emissions impact should be minor. Relative to the dirty coal units, the total emissions from all oil/gas units is minor to begin with.

Allowing them to operate at an annual emission rate of up to 0.4 lbs/mmBtu will not contribute significantly to increased emissions, especially since they receive no allowances. If allowances were given, there would be emissions equal to the number of allowances, if not from the specific unit, from some other unit to which the allowances are traded. By not offering allowances, there is only the potential to increase emissions, but only when the units cannot receive gas, or if the gas prices increase drastically. These units will have no incentive to produce emissions, only to operate efficiently.

V. CONCLUSION

Entergy supports this Committee's efforts to address the acid rain problem. It will continue to work with Congress and the Administration in a constructive way, but will seek changes it believes are more equitable yet still consistent with the goal of controlling the acid rain problem. Entergy seeks this Committee's support to prevent the inequities that may come about as a result of this legislation.

In its final form, the acid rain program must be funded by those responsible for the acid rain effects. Utilities with clean records and a history of going the extra mile to protect the environment should not be required to do more than those who have done nothing. Otherwise, it will be ratepayers, located in one of the poorest regions of the country, who will suffer.

STATEMENT OF
THE AMERICAN GAS ASSOCIATION
AND
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON
ACID RAIN PROPOSALS

January 24, 1990

- -

Mr. Chairman and Members of the Committee:

The American Gas Association (A.G.A.) is a national trade association comprised of some 250 natural gas distribution and transmission companies serving over 166 natural gas consumers throughout the United States. The Interstate Natural Gas Association of America (INGAA) is a national trade association representing the interstate natural gas pipelines of the United States and the interprovincial pipelines of Canada. We appreciate this opportunity to present the views of the natural gas industry regarding pending acid rain legislation and the contributions natural gas can make in achieving cleaner air.

SUMMARY

The natural gas industry generally supports Title IV of S. 1630, as reported by the Senate Environment and Public

Works Committee, because it will, among other things, permit states and utilities the flexibility to achieve sulfur dioxide (SO_2) emission reduction goals in an efficient, cost effective manner.

The natural gas industry's interest centers on ensuring that acid rain legislation is flexible and does not discourage the use of natural gas as a compliance measure, either by requiring flue gas desulfurization units (scrubbers), or by subsidizing scrubber technology at the expense of other options.

The increased use of natural gas will mitigate the problem of acid deposition. When combusted, natural gas emits virtually no SO_2 and about one-third the nitrogen oxide (NO_x) emissions of coal. Ongoing research into gas/coal cofiring technologies, where up to 20 percent natural gas is burned in combination with coal, indicates that significant reductions in total SO_2 and NO_x emissions can be achieved. Natural gas cofiring is one of the most promising and cost-effective near-term clean fuel technologies available to help electric utilities achieve our national clean air goals. Repowering boilers to burn natural gas, switching to natural gas on a seasonal basis, or installing gas-fired combustion turbines are also economically and environmentally sound compliance options.

Despite its positive environmental characteristics, the ability of natural gas to serve as a viable acid rain reduction option will depend directly on how an acid rain program is structured. The gas industry's position is that any acid rain program should be based on the principle of maximizing flexibility, allowing the broadest possible latitude to achieve the necessary emission reductions. A freedom of choice approach to acid rain control will encourage electric utilities and others to choose the most efficient compliance option, minimize costs, and allow all compliance alternatives to compete on an equal basis. Title IV of S. 1630 and the Administration's original acid rain proposal embody this philosophy, and A.G.A. and INGAA have endorsed these bills in principle.

We also support S. 1848, introduced by Senators Bingaman and Ford on November 7, 1989. By establishing a research and demonstration program to promote natural gas cofiring, this bill will further the development of new natural gas technologies so essential to a least-cost, flexible acid rain policy.

ELEMENTS OF A FLEXIBLE COMPLIANCE PLAN

A flexible approach to the problem of acid rain should include the following elements:

- Utilities and state authorities making emission reduction decisions should be able to choose from

> the full range of SO_2 and NO_x reduction options. Legislation should for example, directly mandate the installation of scrubbers by utilities, or indirectly impose this option by requiring a very low emissions rate by a limited number of plants. Rather, utilities should be allowed to spread their compliance burden over all their plants, thereby ensuring the availability of least cost control options.

Giving businessmen the widest possible range of options to achieve the desired emission reduction goals will provide the best cooperation and highest chance for success. They are accustomed to deciding between operating costs and capital costs and among several facility options to achieve their other business goals. In pursuit of other goals, they may resist a specific mandated control technology if a more viable one would accomplish the same goals.

Some opponents of acid rain legislation have argued that Congress is attempting to legislate utility decision making. To some extent, this may be true, although we believe S. 1630 and the President's bill is designed to be flexible for plant operators. Nevertheless, this is not the first time Congress has been asked to legislate utility decisionmaking. In 1978, with passage of the Powerplant and Industrial Fuel Use Act, Congress legislated coal as the appropriate fossil fuel for utility use, believing that natural gas was a rapidly diminishing resource. Of course, those predictions proved wrong, Congress subsequently repealed those prohibitions on natural gas usage, and today, natural gas is an extremely attractive option for electricity generation.

Given that experience, Congress should regard suggestions to mandate specific acid rain control technologies to the exclusion of alternatives with great skepticism.

- Legislation should allow for emission trading, giving states and utilities the ability to achieve reduction targets on a system-wide, state-wide or regional basis, rather than requiring each plant to meet a specific emission rate.

Most of the pending bills in Congress incorporate this concept to some degree. S. 1630 allows trading of allowances, including interpollutant trading with 1.5 lbs of NO_x equal to 1.0 lbs. of SO_2. Basic cofiring alone does not achieve as large a percentage of SO_2 reductions on a single plant as does a scrubber or fuel switching, thus it will likely not be the method by which large-scale SO_2 emission reductions are obtained at a single plant. On the other hand, it can be a very attractive option for a company or an area with multiple plants. An effective trading program will encourage cofiring to be implemented where it does make economic sense and will allow those reductions to be counted toward the utility's or state's overall tonnage reduction requirement. In this way, trading will minimize the overall economic impact of the bill and improve the efficiency of the program.

- Legislation should allow emission reductions to be achieved on an annual basis rather than on a continuous or monthly basis.

Emission standards for new plants are set on a continuous basis, but there is no compelling reason to apply this standard to the reduction of emissions from older plants, where the objective is to achieve certain annual tonnage reductions. Annual averaging will facilitate trading arrangements and allow utilities the flexibility to use more natural gas in the summer months. The summertime is when electric demand peaks, when pipeline capacity is most readily available and when acid deposition peaks. Because of higher residential demand during the winter months, natural gas may not be available to utilities in certain parts of the country 365 days a year. A utility executive faced with a continuous or monthly SO_2 compliance requirement would understandably be hesitant to choose a natural gas option, even where it made economic and environmental sense. We are pleased that S. 1630 uses annual emissions standards as a basis for reductions.

- Legislation should allow NO_x-for-SO_2 trading.

This feature, unique to the Administration bill and S. 1630, is an innovative idea that will further the goals of clean air and economic efficiency. Natural gas technologies are particularly effective in reducing emissions of NO_x, a requirement of all the bills introduced in Congress to one degree or another. An interpollutant trading feature will not only encourage NO_x reductions beyond those otherwise called for, but it also will create a mechanism whereby additional electrical generation can be accommodated without breaching the SO_2 tonnage cap in the bill. The interpollutant trading incorporated into S. 1630 is one of the many reasons why we have endorsed Section IV of the bill.

COST-SHARING

We are pleased that S. 1630 does not contain cost-sharing provisions. We urge the Energy Committee to join in the Environment Committee's resolution that the allowance program effectively achieves the fair allocation of the costs of reduction and that broad based taxes and emissions fees are undesirable.

The natural gas industry opposes the cost sharing programs as set forth to date in some of the acid rain proposals introduced in the House. Our opposition rests on two principles: such cost sharing programs would encourage utilities to install capital intensive technologies, and thus would discriminate against other control options; and, most cost sharing proposals include a tax on natural gas-fired electricity to help fund the program, even though natural gas emits virtually no SO_2. While we support

S. 1630 in this regard, our associations will continue to evaluate all the cost-sharing proposals that are advanced during consideration of the acid rain legislation in light of these principles.

Certain acid rain bills also contain additional subsidies for clean coal technologies, in some cases with the money coming from the fee on electricity. The natural gas industry supports the current clean coal research and development program. Indeed, gas/coal cofiring research has benefited from the program. However, this legislation should not become a vehicle for providing subsidies for commercial installation of clean coal technology in utilities. The result of such a program will be to subsidize capital intensive, rather than operating cost intensive yet, more efficient, approaches to emission reductions.

The natural gas industry does not seek commercialization funds for its clean coal options, and we oppose providing such funds for other technologies. The current DOE Clean Coal Program is structured to demonstrate the commercial feasibility of the technology; therefore, no further funding support should be necessary.

Repowering units with clean coal technology affords substantially increased capacity with lower emission rates. While we oppose a subsidy for clean coal, there should be some incentive to invest in clean-coal. The Senate Environment Committee recognized this in S. 1630 by providing for a time extension of emissions limitations.

It is in the national interest to encourage the utilization of those natural gas technologies that reduce SO_2 and NO_x emissions resulting from the combustion of coal. Thus, we urge a similar extension for the retrofitting of natural gas cofiring technologies demonstrated as part of DOE's Clean Coal Technology Programs. In addition, we urge that natural gas cofiring and reburn be expressly identified in S. 1630 among the technologies eligible for this extension.

Further, current and emerging natural gas technologies should be allowed to play their vital role in the clean air scheme. Therefore, we recommend that the Clean Air Act be amended so that New Source Performance Standards are not triggered by the increase of any actual or potential emissions due to the installation, operation or cessation of technologies that burn natural gas with coal in an electric utility or industrial boiler. Because there are clean coal projects that are being held up due to the uncertainty on this issue, it is imperative that Congress send a clear signal to EPA. Senator Bingaman's bill contains provisions in this regard and we urge that you incorporate them into any acid rain legislation. If Congress fails to act, utilities will not adopt new technologies for fear that EPA may penalize them at a later date for circumstances beyond their control. This unwillingness to try new technologies will only result in less progress being made in attaining clean air.

USE OF NATURAL GAS AS A MEANS OF ACID RAIN EMISSION CONTROL

As mentioned above, the burning of natural gas with coal can help reduce utility emissions of SO_2 and NO_x, precursors of acid rain. Four technologies have been used to reduce emissions occuring from combustion of coal:

- **basic cofiring** -- where the supplemental firing of nominally 1 - 10 percent natural gas provides emission reductions and operational enhancements;
- **gas reburn** -- where 15 - 20 percent gas injection provides 50 - 60 percent NO_x reductions and operational benefits;
- **gas reburn/sorbent injection (GR-SI)** -- where the mating of these two technologies provides 50 percent SO_2 and 60 percent NO_x reductions; and
- **gas substitution** -- where gas is substituted for coal or high sulfur oil on a seasonal or year-round basis, virtually eliminating SO_2 and particulate emissions, while also significantly reducing NO_x emissions.

In addition, there are other gas and coal-using technologies that you will hear more of in the months to come. These include the NOXSO process, which achieves simultaneous sulfur and nitrogen oxide reductions, and the SNOX process, which can simultaneously reduce both SO_x and

NO_x by perhaps as much as 95 percent. These technologies are well worth developing and, could actually prove to be more effective than scrubbers. They should not be precluded by inflexible legislation.

Basic Cofiring

Basic cofiring of coal with natural gas involves the injection of gas into the boiler to provide a fraction of its total heat input. Originally, it was thought that this technique would reduce the amount of SO_2 emissions in the same proportion that gas was used in the boiler. However, a recent field evaluation at the Cheswick power station in Pennsylvania found that even greater than proportional reductions of SO_2 occurred. That test, which involved a 570 MW tangentially-fired boiler, found that cofiring 1 percent - 3 percent gas could obtain SO_2 reductions of approximately 3 percent - 10 percent. Similarly, 6 percent to 12 percent gas cofiring could reduce NO_x emissions by 10 percent - 25 percent.

This test demonstrated that cofiring yields many other positive operational and environmental benefits in addition to the SO_2 and NO_x emissions reductions. These benefits include a reduction of particulates, improvement of fly-ash quality, start-up improvement (if gas was not previously used), availability improvement, operation and maintenance cost reductions, peaking capacity increases, turn-down capability improvement, and boiler efficiency improvement.

Gas Reburn

Reburn technology is aimed primarily at reducing power plant NO_x emissions. As in cofiring, reburn involves using gas as a small portion of the boiler fuel. Unlike basic cofiring, however, reburn technology involves injecting that fuel into a zone beyond the primary combustion zone to create a natural gas rich "reburn" zone. Over-fire air is added in a final burnout zone to complete the overall combustion process. In this reburn zone, much of the NO_x present is converted back to elemental nitrogen and water vapor.

Pilot tests indicate that a majority of cyclone boilers could successfully apply this technology in order to reduce their NO_x emissions by approximately 60 percent. This is particularly significant as no other commercially demonstrated NO_x reduction technique exists for these boilers. Although the majority of cyclone units are 20 - 30 years of age, utilities plan to operate many of these units for at least an additional 10 - 20 years. In addition, the majority of these units are in the Midwest, an area targeted for acid rain and ozone emissions control.

Gas reburn combined with dry sorbent injection (GR-SI) refers to combining reburn techniques with the injection of dry calcium-based sorbent in the over-fire air area of the boiler to reduce SO_2 emissions. Combining gas reburn with sorbent injection avoids the cost and complexity of other types of sorbent injection technology, improves sorbent utilization, reduces the amounts of sorbent required, and decreases the additional particulate burden on the plant's precipitator. Using a 15 percent to 20 percent proportion of natural gas in a GR-SI configuration is expected to achieve the NO_x reductions cited above and also reduce SO_2 emissions by 40 percent to 60 percent compared to a coal only fired boiler. Attachment A illustrates the GR-SI approach in which sorbent material is injected into the "burnout zone" to capture SO_2 released from coal burned in the primary combustion zone.

GR-SI is considered applicable to all boiler designs, is more easily retrofitted than scrubber technology, and may offer some site-specific operational enhancements. The best opportunities for applying GR-SI are projected to occur on medium to smaller size units (less than 500 MW), units with shorter remaining economic lives, and will probably be utilized at moderate to low capacity factor units. Such units would typically have been built in the 1950s and 1960s.

To date, basic cofiring has been tested at one commercially operational plant. As the Gas Research Institute (GRI) has explained in its testimony, tests of all three cofiring technologies are scheduled to begin at six other power plants within the next year. Three of these projects are in Illinois and the others are located in Indiana, Oklahoma and Ohio. These projects are being funded from a variety of sources, including the natural gas industry and, in some cases, the Department of Energy. In all, a total of almost $52 million will be invested in cofiring demonstration projects.

Economics of Cofiring

The economics of using a particular natural gas cofiring technology at any given utility facility depend on a variety of factors, including size, other technical options, age of the plant, capacity factors, the sulfur content of the coal used, and the availability and cost of gas. A.G.A. and INGAA have examined the practicality of supplying gas for cofiring at 50 of the largest SO_2 emitting power plants. The variables considered were distance to the utility, hookup costs and balance-of-system costs (additional pipeline system upgrade costs necessary to serve the new load). If the two most expensive plants to hookup are excluded, the average cost per mile is about $310,000 and about half the plants were 10 miles or less from a gas system. Also, for 90 percent of the cases, the hookups could be constructed within nine months. Thus, not only is the cost of providing service minimal compared to scrubbers, it can be implemented in a relatively short time period. A copy of this report is attached.

The capital costs of actually modifying a plant to accommodate cofiring is estimated to range from $2 to $4/kw for basic cofiring, $15-$30/kw for gas reburn, and $50-$100/kw for reburn combined with sorbent injection. This compares to an average of $310/kw for scrubber installation.

An economic analysis performed by the GRI examined the market potential for GR-SI technology as compared to scrubbing or fuel-switching for power plants. This analysis shows that the GR-SI option could result in additional gas consumption of 211 Bcf to 750 Bcf of additional gas demand annually in up to 250 individual boiler units. The analysis found that the expected price of gas to the utility was the most significant factor in determining the choice between gas and other alternatives, and the range of volumes cited above reflect alternative price scenarios.

EMPLOYMENT IMPACTS

Cofiring is beneficial to the coal industry as well as the gas industry. By generating additional demand for natural gas, cofiring would help stimulate additional employment opportunities in the gas production and pipeline construction sector. At the same time, cofiring allows utilities to continue to use their current coal supplier when the plant would otherwise be forced to switch fuels or possibly even close.

An economic study done at Southern Methodist University assessed the impact of higher natural gas production in Texas on employment. The study found a potential gain of 22,614 new jobs (including support and associated services) in Texas from an increase of just 379 Bcf of natural gas production. Based on this relationship, the employment growth resulting from expanded gas demand of 200 Bcf to 750 Bcf would be 12,000 to 45,000 jobs.

While cofiring would help create jobs in the gas industry, it would be wrong to assume automatically that these gains come at the expense of existing coal mining jobs. In fact, in many instances, cofiring could actually help protect certain mining jobs that would otherwise be in jeopardy by allowing plants to remain in normal operation and use current coal supplies.

This can be illustrated by considering the situation that many utilities must face. Given the need to reduce emissions from existing plants, a utility is faced with the choice of installing a scrubber, switching to low sulfur coal, oil or natural gas, or cofiring. Undoubtedly, the scrubber option will preserve current coal industry employment patterns by allowing plants to continue using the current coal supplies. But for many plants, scrubbers may be impractical since scrubber economics will be less favorable for older and smaller plants. In other cases, plants may not have the physical space for a scrubber, or an operator may need to achieve NO_x reductions in addition to SO_2 reductions. In these instances, the choice is between fuel switching, plant output reductions, and cofiring. Thus, given these alternatives, cofiring is the only option that preserves high sulfur coal jobs.

Further, a significant number of plants may not have the option to install new scrubbers. While it is difficult to determine with precision the thresholds beyond which installing new scrubbers becomes impractical, there are 550 boiler units under 300 MW in size and over 30 years of age. These 550 plants burn 84 million tons of coal annually which, based on industry employment indices, would support the employment of 16,000 mine workers.

Thus the employment impacts of cofiring must be viewed in light of the alternatives facing the utility. In many cases, cofiring may be the least disruptive and most economic option and may preserve jobs that otherwise would be lost.

NATURAL GAS SUPPLY OUTLOOK

There is a more than adequate gas supply to meet the needs of complying with acid rain legislation. A.G.A estimates that supply is adequate for gas to maintain at least a 20-to-25 percent share of the nation's total energy depending on the price scenario. Moreover, we estimate that gas supply in the year 2010 will be between 18.4 and 24.2 Tcf depending upon the pricing scenario. The 24.2 Tcf level represents a 37 percent increase over the 1988 level of actual gas supply.

As demand rises, the market for natural gas improves, creating an incentive for increased drilling and production. So long as the domestic market for the natural gas resource base remains free of price controls and other artificial market constraints, the resource base is large enough to meet substantially higher levels of gas demand. Together with supplemental sources of gas, such as Canadian or Mexican imports, the resource base is also large enough to overcome the results of occasional marketplace misjudgments. Historical shortages have been due to improper price signals rather than a true resource shortage.

Our industry does not stand alone in pointing to a large domestic natural gas resource base. This conclusion also has been reached in a landmark study on natural gas supplies by the U.S. Department of Energy (DOE) entitled, An Assessment of the Natural Gas Resource Base of the United States.

In this May, 1988 study, which drew upon the technical and scientific knowledge of a number of expert panelists, DOE focused on conventional natural gas resources that are domestically available and can be recovered with today's technology. The study found that, in the lower 48 states alone, the proven reserves and currently undiscovered supplies total 1,059 trillion cubic feet (Tcf). At today's level of nationwide gas consumption, this amount is equivalent to a 62-year supply.

DOE further found that, of this 62-year supply of technologically recoverable gas, the equivalent of a 35-year supply is available at wellhead prices below $3.00 per MMBtu. This wellhead price range is not too different from prices that occur at the peak of the winter heating season. DOE also found that this 35-year supply can rise to a 45-year supply if wellhead prices rise to a level of $5.00 per MMBtu. This range is markedly above today's prevailing prices, but still within the historical experience of gas consumers in the early 1980s.

It is important to note that these supply figures do not include vast natural gas resources in Alaska (estimated by DOE at 129 Tcf), Canada and Mexico. Nor do they include possible supplies from unconventional domestic sources that may be accessible in the future. These resources are known but not technologically accessible under prevailing industry economics without federal research and development funds.

In short, DOE's estimates of gas ultimately available to American consumers can be considered conservative. We add that DOE's resource base estimates are similar (when Alaska is included) to the most recent estimates made by the Potential Gas Committee (PGC), a body of independent experts from throughout the natural gas industry. According to the latest PGC study, in the United States, conventionally recoverable gas at year-end 1988 was 836 Tcf (this includes "proven" reserves, which are already known to exist). At current gas consumption rates of roughly 17 Tcf per year, the PGC estimate is equivalent to a 57.8 year supply.

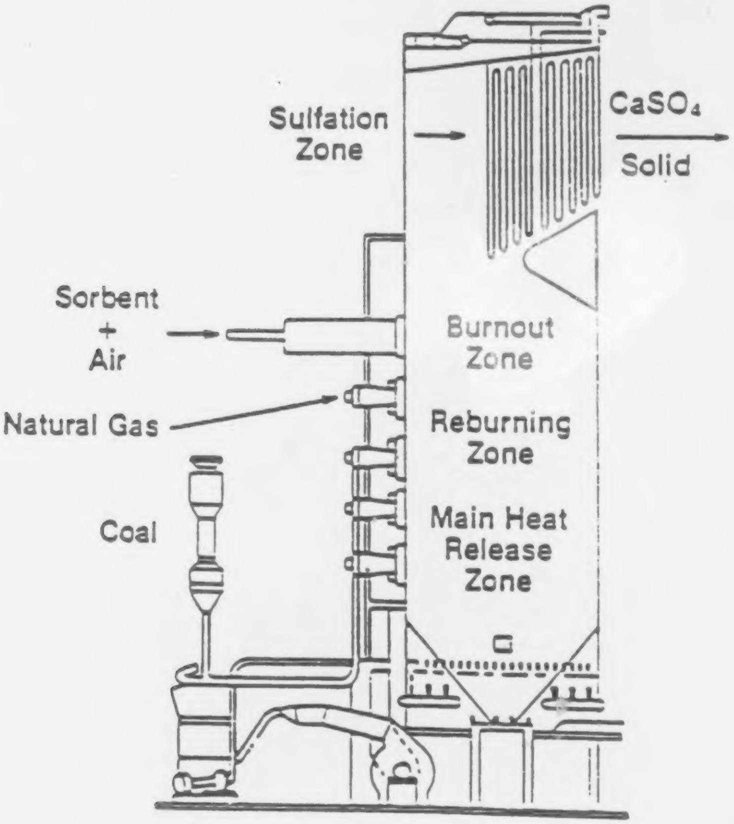
Again, we do not claim that natural gas is a panacea for the control of acid rain. We do expect natural gas to be responsible for achieving approximately one-fifth of the ten million ton reduction called for in most bills. The supply is more than adequate for gas to play a meaningful role in reducing acid rain deposition with minimum costs to the country. It also has the advantage of being easy and quick to implement as a compliance strategy.

CONCLUSION

In conclusion, Title IV of S. 1630 as reported by the Senate Environment and Public Works Committee combines the elements A.G.A. and INGAA believe important in an acid rain program, and we generally support that legislation. We respectfully urge members of this Committee to support Title IV of S. 1630 with our suggested changes as outlined above. The natural gas industry believes that a flexible approach to acid rain legislation will best serve both the electric and gas utilities, their suppliers, their customers and our national economy. By letting plant owners and operators, together with their state and regional decisionmakers, choose the most economical and effective control options for their particular systems and regions, national environmental goals can be achieved in a least-cost manner.

ATTACHMENT A

GAS REBURNING–SORBENT INJECTION


Sulfation Zone
$CaSO_4$
Solid
Sorbent + Air
Burnout Zone
Natural Gas
Reburning Zone
Coal
Main Heat Release Zone

BACKGROUND REPORT

89-4
June 1989

CO-FIRING OF NATURAL GAS IN ELECTRIC POWER PLANTS: ARE PIPELINE HOOKUPS FEASIBLE?

EXECUTIVE SUMMARY

This report describes the methodology and results of a joint INGAA-AGA survey to determine the feasibility of providing natural gas services for co-firing at certain power plants. The survey covered interstate pipelines and local distribution companies operating in the vicinity of 50 of the largest power plants in terms of sulfur dioxide (SO_2) emissions. Co-firing of natural gas and coal has been proposed as an effective and economic strategy for lowering SO_2 and nitrogen oxides (NO_x) emissions from coal-fired boilers in power plants.

A total of 18 pipelines and nine local distribution companies responded to the survey, each providing data on one or more of the 50 plants. In some cases, as many as four companies provided information on serving one plant. The responses indicate that service to all 50 plants is possible. The average total cost per plant was $6.4 million, but is influenced by a few costly cases. If the two most expensive plants to hookup are excluded, the average cost was $4.1 million per plant. For the least expensive 48 plants to hookup, the average cost per mile was about $310,000. About half the plants were 10 miles or less from a gas system, and only seven were more than 20 miles away from one. For ninety percent of the cases, the hookups can be constructed within nine months.

PREFACE

A Background Report is an INGAA document which presents the results of research into a particular technical area of interest to those who wish a deeper understanding of the interstate natural gas industry. Background Reports are not aimed at in-depth discussion of policy issues. Rather, they summarize research intended to help illuminate some of the consequences of public policy initiatives. The information contained in this report was requested of INGAA and the American Gas Association (AGA) by the Office of Fossil Energy of the U.S. Department of Energy as part of its evaluation of possible options for the administration's position on new Clean Air Act reauthorization legislation.

This report was prepared by INGAA and is based on information collected by INGAA and AGA through a survey of their respective members. Any questions or comments should be directed to Samir Salama of INGAA (202/626-3200).

INTRODUCTION

In April, 1989, the Office of Fossil Energy of the U.S. Department of Energy asked INGAA and AGA to help its efforts to assess the feasibility of using natural gas co-firing as a means of reducing air emissions from electric utility power plants. The Office of Fossil Energy was seeking facts about:

- The feasibility of providing natural gas capacity by interstate pipelines and local distribution companies to serve the environmental needs of at least the top 50 sulfur dioxide-emitting power plants in the U.S.,
- The average cost of lateral hookups to deliver sufficient amounts of gas to these plants, and
- Environmental factors that might delay construction of the hookups beyond the normal nine-month pipeline construction cycle.

OVERVIEW OF THE TECHNOLOGY

Among the various methods to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emitted from electric utility generating plants, co-firing technologies are an option that holds great promise. Co-firing of natural gas with coal involves the concurrent burning of gas and coal in a boiler whereby gas provides a fraction of the boiler's total heat input.[1] There are three types of co-firing technologies applicable to coal-fired boilers:

- Basic co-firing: where 1 to 10 percent of the heat input to the boiler is supplied by gas introduced with coal in the primary combustion zone.
- Reburn co-firing: where 15 to 20 percent of the heat input is derived from gas introduced in a post-combustion zone to reduce SO_2 and NO_x emissions.
- Reburn with sorbent[2] injection (SI): where a sorbent is injected beyond the reburn zone primarily to reduce SO_2 emissions in addition to the NO_x reductions achieved by reburn alone.

The SI option is of special interest because it is being proposed as applicable to most boiler designs and is less expensive to install and operate than other options for flue gas desulfurization, including scrubbers. The best candidates for SI are expected to be units that are small to medium capacity (less than 500 MW), have remaining economic lives of ten to fifteen years and are operated at moderate to low capacity factors as cycling

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[1] Recent experiments at the Cheswick power plant in Pennsylvania yielded reductions of SO_2 and NO_x emissions that are more than proportional to the amount of gas used.

[2] A dry calcium-based material, such as calcitic hydrate, is used to capture sulfur oxides from flue gases as they approach the boiler stack.

METHODOLOGY

INGAA and AGA surveyed their members to determine the feasibility of providing gas services to a list of plants representing the nation's top 50 SO_2-emitting power plants (see Appendix A). This list, which also includes plant location, size and utility affiliation, was prepared by DOE's Office of Fossil Energy based on 1985 data. The Office estimated peak day gas requirements for each plant based on co-firing at the maximum rate of 20 percent of the total heat input to each plant.[5] The Office estimated total heat input to each plant conservatively from the plant's total nameplate capacity (in MW) by assuming 100 percent utilization (8,760 hours per year) and an industry average heat rate of 10,000 Btu/kWh. It was assumed that the maximum natural gas loads identified for each power plant would occur in the summer during the off-peak season for gas demand and that current natural gas deliverability at the wellhead would be sufficient to meet this incremental load.

The respondents were asked to identify plants that they could serve and, for each of these plants, provide the following information:

- Construction cost for the least cost route to the plant,[6]
- Distance of that route in miles of pipe,
- Balance-of-system costs[7] to supply that one plant if necessary, and
- Nonmonetary factors that might delay construction.

The respondents were asked also to quantify additional balance-of-system costs if all plants found feasible were to be added to the pipeline or distributor system.

The hookup cost data from both pipelines and distributors were compiled into one database and classified by plant. Balance-of-system costs due to the addition of individual plants were included in these costs. For each plant, the least cost hookup was selected as an initial possibility. If a selected least cost hookup was from a pipeline or distributor with balance-of-system costs for multiple hookups, then the initial cost was revised to include a prorated share of those costs. The prorata share for each plant was calculated as the estimated balance-of-system costs divided by all plants included in those cost estimates.[8] The selection of the least cost routes was then finalized by

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[5] To the extent that not all units within the 50 plants are coal-fired, this estimate of peak day requirement would be overstated.

[6] For operational reasons, the delivery pressure for the plants was selected to be 50 psig (pounds per square inch gauge).

[7] Costs incurred elsewhere on the system to provide this service, including possible upgrades of compressor stations, meters, valves, etc.

[8] This proration is conservative because the balance-of-system costs might only be incurred if

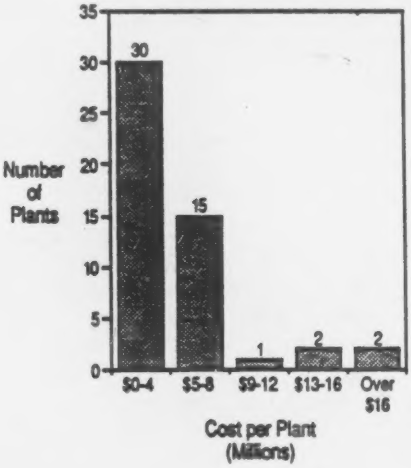
Balance-of-System Costs

Only 7 of the least cost routes to the 50 plants required additional system upgrade and resulted in balance-of-system costs. The balance-of-system costs were significant for two plants, which accounted for $92 million of the total $98 million in balance-of-system costs.

Total Costs

The total costs per plant include both the hookup and the balance-of-system costs. A distribution of the 50 plants based on total costs is shown in Figure 3. The mean total cost per plant for all plants is $6.4 million and the median is $3 million. Once again, the large costs of just a few plants skew the mean. If the two plants with costs over $16 million are removed from the sample, the mean total cost per plant falls to $4.1 million. On a cost per mile basis, the mean for the 50 plants is about $500,000. When the two most expensive plants are excluded, the mean total cost per mile is around $310,000.

Figure 3
Frequency of Plants
Based on Total Cost



Factors That May Delay Construction

Five plants had least cost hookup routes which involve factors that could delay construction. Three plants are located in densely populated areas which could delay the permitting process and hookups to two plants would require crossing a major river. These factors are likely to delay construction of hookups to only these five plants. The remaining 45 plants could be constructed in nine months or less.

CONCLUSIONS

Interstate natural gas pipeline companies and local distribution companies are capable of providing natural gas services to support co-firing at the nation's 50 highest SO_2-emitting power plants. Construction of these hookups can be completed quickly (within 9 months for most plants) and at moderate capital costs relative to other options. Further research would be needed to assess the feasibility and costs of gas hookups to serve co-firing needs of the next tier of 50 to 60 coal-fired power plants.

APPENDIX A

TOP 50 SULFUR DIOXIDE EMITTING POWER PLANTS

(Based on 1985 data)

Plant	Utility	State	County	Size (MW)	Gas Req'd. for 20% Co-firing (MMCF/D)
EC Gaston	Alabama Power Company	AL	Shelby	1880	90
Colbert	Tennessee Valley Authority	AL	Colbert	1350	65
Big Bend	Tampa Electric Company	FL	Hillsborough	1794	86
Crist	Gulf Power Company	FL	Escambia	1002	48
Wansley	Georgia Power Company	GA	Heard	1730	83
Harlee Branch	Georgia Power Company	GA	Putnam	1540	74
Yates	Georgia Power Company	GA	Cobb	1250	60
Bowen	Georgia Power Company	GA	Bartow	3160	152
Coffeen	Central Illinois Public Service	IL	Montgomery	913	44
Kincaid	Commonwealth Edison Company	IL	Cristian	1182	57
Baldwin	Illinois Power Company	IL	Randolph	1892	91
Joppa	Electric Energy Inc.	IL	Massac	1098	53
Gibson	Public Service Indiana	IN	Gibson	3340	160
Clifty Creek	Indiana Kentucky Electric Corp.	IN	Jefferson	1303	63
Cayuga	Public Service Indiana	IN	Vermillion	1070	51
Paradise	Tennessee Valley Authority	KY	Muhlenberg	2558	123
Ghent	Kentucky Utilities Company	KY	Carroll	2044	98
Braton Point	New England Power Company	MA	Bristol	1600	77
Monroe (MI)	Detroit Edison Company	MI	Monroe	3152	151
Montrose	Kansas City Power & Light	MO	Henry	494	24
New Madrid	Associated Electric Coop.	MO	New Madrid	1200	58
Labadie	Union Electric Company	MO	Franklin	2482	119
Thomas Hill	Associated Electric Coop.	MO	Randolph	1213	58
Roxboro	Carolina Power & Light Company	NC	Person	2558	123
Kyger Creek	Ohio Valley Electric Corp.	OH	Gallia	1086	52
Eastlake	Cleveland Electric Illum. Co.	OH	Lake	1257	60
Cardinal	Cardinal Operating Company	OH	Jefferson	1880	90
WH Sammis	Ohio Edison Company	OH	Jefferson	2304	111
Genl. JM Gavin	Ohio Power Company	OH	Gallia	2600	125
JM Stuart	Dayton Power & Light Company	OH	Adams	2441	117
Miami Fort	Cincinnati Gas & Electric Co.	OH	Hamilton	1292	62
Muskingum River	Ohio Power Company	OH	Morgan	1530	73
Conesville	Columbus & So. Ohio Electric	OH	Coshocton	1941	93
Conemaugh	Pennsylvania Electric Co.	PA	Indiana	1872	90
Montour	Pennsylvania Power & Light	PA	Montour	1647	79
Brunner Island	Pennsylvania Power & Light	PA	York	1558	75
Keystone	Pennsylvania Electric Co.	PA	Armstrong	1872	90
Hatsfields Ferry	Western Pennsylvania Power Co.	PA	Greene	1728	83
Homer City	Pennsylvania Electric Company	PA	Indiana	1970	95
Gallatin	Tennessee Valley Authority	TN	Sumner	1255	60
Johnsonville	Tennessee Valley Authority	TN	Humphreys	1485	71
Cumberland	Tennessee Valley Authority	TN	Stewart	2600	125
Centralia	Pacific Power & Light Company	WA	Thurston	1330	64
Oak Creek (WI)	Wisconsin Electric Power Co.	WI	Milwaukee	1552	74
Kammer	Ohio Power Company	WV	Marshall	712	34
Harrison	Monongahela Power Company	WV	Harrison	2052	98
Mount Storm	Virginia Electric & Power Co.	WV	Grant	1662	80
Mitchell (WV)	Ohio Power Company	WV	Marshall	1632	78
Amos	Appalachian Power Company	WV	Putnam	2933	141
Fort Martin	Monongahela Power Company	WV	Monongahela	1152	55

Statement of

James E. Rogers, Jr., Chairman and Chief Executive Officer

Public Service Company of Indiana

Concerning

Energy Policy Implications of S. 1630

Submitted for the Record to the

Senate Committee on Energy and Natural Resources

January 24, 1990

Mr. Chairman and distinguished members of the Committee, I am James Rogers, chairman and chief executive officer of Public Service Company of Indiana (PSI). I thank you for the opportunity to present PSI's views on the critical issue of the energy policy implications of S. 1630.

Prior to serving PSI, I worked both as Deputy General Counsel at FERC and as Vice President of the country's largest natural gas transmission company. As a consequence, I have had many occasions to consider the types of energy policy questions raised by S. 1630 from a variety of perspectives, including those of energy regulator, natural gas transporter and distributor, and now as a generator and distributor of electric energy.

Public Service Company of Indiana is an investor-owned utility that provides electric power to 69 of Indiana's 92 counties. We serve 570,000 customers, including 500,000 residential, 67,000 commercial and 2,700 industrial customers. Our commercial and industrial customers employ approximately 1.5 million people in our service territory.

In the last decade, our company has worked hard to reduce our sulfur dioxide emissions. Since 1980, we have cut SO_2 emissions by 22 percent and reduced our overall SO_2 emissions by 110,000 tons per year. Indiana's new state implementation plan will result in even greater reductions at our facilities, regardless of future congressional action. Our Gibson 5 scrubber is one of the nation's most efficient, winning a 1987 EPA award for outstanding operation.

PSI is also working to develop new technologies that will allow the continued use of U.S. coal resources -- specifically high sulfur coal -- while minimizing the adverse environmental consequences. We hope to have a project funded in the next round of DOE's Clean Coal Technology programs. We feel the development of clean coal technologies is vital to the continued use of millions of tons of secure and economical domestic coal reserves.

PSI has been working for many months with both Congress and the Administration to help shape legislation that addresses the nation's concerns about acid rain. Indeed, I shared my views on the environmental policy issues raised by the bill with the House Energy and Power Subcommittee and the Senate Environment and Public Works Committee last fall.

The issue before this Committee is whether the Clean Air Act reauthorization bill is crafted so as to achieve the bill's important environmental goals consistent with sound national energy policy. As currently drafted, S. 1630 will adversely affect coal markets, employment, and electricity rates.

Loss of Regional Coal Resources. S. 1630 will drive utilities to select low-sulfur fuels for existing and new utility plants, drying up the market for Midwestern and Northern Appalachian coal and thereby depriving the U.S. of both short and long-term use of these valuable and dependable energy resources.

Regional Unemployment. S. 1630 will cause the elimination of between 22,000 and 30,000 coal mine jobs in the Midwest and Northern Appalachia. In addition, thousands of non-mining jobs will be lost in mining communities throughout the region as the economic base of these towns is eroded.

Unfair Rate Increases. S. 1630 will cause dramatic electricity rate increases in the Midwest (up to 25 percent for PSI's customers), resulting in substantial hardships for captive residential and commercial customers and flight of price-sensitive industrial customers, causing further rate spirals. This is an energy problem caused in part by the bill's inequity--the rate impacts are so great in the Midwest because S. 1630 burdens our ratepayers with a substantially disproportionate share of the clean-up responsibilities.

Fortunately, these problems can be overcome without sacrificing the environmental goals of S. 1630, to which PSI wholeheartedly subscribes. The solution is a subsidy for capital investments in pollution control equipment. A capital subsidy would encourage the continued use of the nation's abundant Midwestern coal reserves by giving large coal customers an incentive to invest in pollution control equipment instead of switching to other fuel supplies. That alone will further national energy security interests. Moreover, a capital subsidy would offer some relief to the ratepayers in our region who are being asked to pay more than their fair share of the clean-up costs.

ABANDONMENT OF DEPENDABLE MIDWESTERN COAL RESOURCES

To comply with S. 1630, PSI anticipates that it will bring its facilities into compliance by constructing five new scrubbers on major coal burning units, with a total compliance cost of $1.4 billion. Let me explain why PSI will likely choose scrubbing as opposed to fuel switching as our compliance strategy. First, PSI, like many utilities, has long-term contracts with its coal suppliers. In some instances, these contracts can be modified before the term is expired. But often, the utility must pay substantial penalties, at a great cost to the ratepayers. Second, PSI's choice of coal is constrained by the design of its electricity generating units. For example, certain low sulfur western coals cannot be burned in our units because of incompatible ash fusion temperatures and other chemical and combustion characteristics. In addition, PSI is the largest purchaser of coal from southern Indiana -- the very region it serves. The economic viability of the communities in which PSI's customers live and work is closely tied to regional mining operations. These are important considerations that my company must weigh in choosing a compliance strategy.

Unfortunately for the nation, many utilities do not share PSI's commitment to continued use of local coal resources. Consequently, if S. 1630 were enacted in its current form, many utilities would choose to switch existing units from high-sulfur coal to low-sulfur coal as a means of compliance. Moreover, the bill will push utilities to abandon existing plants and rely instead on wholesale purchases (including, ironically, purchases from coal-burning utilities in Canada), and new plants fueled by oil or natural gas. The question, then, is whether such a dramatic shift in coal and other energy markets is consistent with national policy. PSI submits that it is not.

The shift away from Midwestern and Northern Appalachian coal will result in the deactivation of existing coal mines in those regions. In many instances, underground coal mines cannot economically be reopened once they have closed down operations. The mine itself may become flooded and structurally unsound; the machinery may be removed; the miners may move away or be trained for other jobs; and the mining town itself may disappear once mining operations cease. Even when reopening a coal mine is possible, there is great time and expense involved in returning the underground network to a safe condition and rehiring coal miners. Once these coal facilities are closed down, it is difficult or impossible to bring them back into service when the need for this coal arises, as it ultimately will.

Policies that will close down mines in the Midwest and Northern Appalachia reduce the flexibility in the American energy market. The nation will lose the opportunity to draw on these dependable coal resources in an unanticipated energy market crisis caused by production or transportation problems , such as another oil embargo, a railroad strike, natural gas shortages or a freeze in the Mississippi River system. As with other nationally important production capacity, Congress should be hesitant to implement policies that will result in the shutting down of coal facilities on the basis of short-term abundance of alternative fuels. Moreover, the objectives of clean air do not require that we pursue such a short-sighted energy policy.

Recent events have demonstrated that increasing electric utilities' reliance on oil and gas could put ratepayers in a vulnerable position. As we all remember, the OPEC cartel caused significant oil shortages and skyrocketing energy prices in the 1970's. U.S. vulnerability to such events has risen dramatically in recent years: The American Petroleum Institute recently announced that imports now account for 46 percent of U.S. petroleum consumption, a ten-year high. Similarly, there were natural gas shortages as recently as December 1989 due to elevated demand during a cold snap. Indeed, natural gas shortages forced some electric utilities to rotate power supplies to industry and other electric utilities to switch to oil. This experience should cause Congress to think twice before actively encouraging utilities to switch to oil or natural gas, when the consequences of switching may include subjecting ratepayers to spiraling fuel prices and perhaps even brownouts or blackouts in times of shortage.

The most important human impact of fuel market changes driven by the absence of an incentive for investing in pollution control is the loss of tens of thousands of mining jobs. Indiana and the region face serious losses in mining and mining-related employment if S. 1630 is enacted in its current form. The United Mine Workers of America estimates this loss at between 22,000 and 30,000 jobs, and Administrator Reilly has acknowledged that S. 1630 will cause the loss of 17,000 mining jobs in the region. The state of Indiana estimates that more than 1,500 mining jobs would be lost in the state alone, even assuming that Hoosier utilities will comply primarily by installing scrubbers rather than by fuel switching.

Congress should not underestimate the human suffering that will be caused by this bill, even if it tends, at least initially, to be regional in scope. In the past, Congress has recognized that national problems must be solved with national solutions. It should recognize that today's unemployment in Indiana, Ohio or Illinois may well become tomorrow's national economic recession.

UNFAIR RATE IMPACTS AND THE LOSS OF INDUSTRIAL RATEPAYERS

With $1.4 billion in compliance costs, PSI estimates that the cumulative rate impact of acid rain compliance under S. 1630 will be 25 percent by the year 2001. Independently, the state of Indiana estimates the cumulative rate impact for PSI customers will be 21 percent.

Put simply, this means a significant increase in the electric bills of our customers. The typical residential consumer, with a monthly bill of $50, will face an increase of $10 to $12 per month, or an annual increase of $120 to $150. These increases will impose great personal hardships on low- and fixed-income households.

As already noted, this rate increase will also mean higher unemployment for Indiana. The state of Indiana estimates that more than 20,000 jobs will be lost or adversely affected because of rate increases caused by this bill. Thus, the rate shock impact substantially exacerbates the mine-related unemployment effects.

Higher rates for industrial customers will lead to a vicious rate spiral for captive ratepayers. As substantial rate increases take place, more and more industrial customers will choose to move to another region with cheaper (and possibly government-subsidized) electricity, to use other fuels in lieu of electricity, or to generate their own electricity. Indeed, the move toward self-generation is doubly encouraged by the bill because there is no requirement that new industrial sources acquire allowances. As industrial customers leave the utility systems, the captive commercial and residential customers will be left to carry larger and larger shares of the fixed costs of utility operation.

These rate impacts are both substantial and palpably unfair. S. 1630 requires that Indiana and several other states make far more than their fair share of emission reductions. For example, Indiana contributed 7.5 percent of the nation's SO_2 emissions in 1980, but it is asked to make 11.8 percent of the required emission reductions under S. 1630 -- more than 50 percent over its fair share. This is inconsistent with the "polluter pays" principle espoused by the bill's supporters. "Polluter pays" does not mean that our ratepayers pay fifty percent too much while industrial sources (which account for roughly one-quarter of nationwide SO_2 emissions) and many utility sources are not required to make any reductions nor contribute to the cost of emission reductions made on their behalf by others such as PSI.

PROMOTING THE NATION'S ENERGY SECURITY BY ENCOURAGING INVESTMENTS IN POLLUTION CONTROL EQUIPMENT

PSI supports an acid rain policy that encourages investment in flue gas scrubbers and thus promotes the continued use of locally-available high-sulfur coal resources, but still leaves the choice of compliance technique to the utility. For example, Chairman Dingell has offered a balanced proposal, which would provide financial assistance for Phase I capital expenditures without mandating the use of scrubbers, and would grant Phase II subsidies for emission reductions resulting from any means. Alternatively, investments in pollution controls could be encouraged with an investment tax credit or other tax incentive. A policy favoring pollution control investments can be constructed so as to give special encouragement to specified types of preferred compliance investments, such as investments in conservation or clean coal technology.

A subsidy for capital investments in pollution control equipment would dampen the otherwise potentially wild swings in the fuel markets that could result from this acid rain legislation. In this regard, it must be remembered that Congress actively promoted the use of coal in the 1978 Fuel Use Act as security against international oil market disruptions. In light of that recent history, Congress has a responsibility to employees in the coal industry to mitigate dramatic fluctuations in energy markets driven by the vicissitudes of national priorities.

Capital investment subsidies will also act to mitigate the inequitable rate impacts caused by S. 1630. By offering some assistance to the utilities required to make the most dramatic, and disproportionate, emission reductions, a subsidy for pollution control investments will help out ratepayers who are hardest hit by S. 1630.

FAIRLY FUNDING A CAPITAL INVESTMENT SUBSIDY

A fee on SO_2 (and possibly NO_x) emissions from both utility and industrial sources, as proposed by Chairman Dingell, is the funding mechanism most consistent with the "polluter pays" philosophy. With an emissions fee, utilities that use non-fossil fuel technologies, burn low-sulfur fuels, or have invested in emission reduction technologies will not be required to "pay twice." Emitters would pay in direct proportion to their actual emissions. The fee would be set so that the revenues generated would equal the reimbursement needed to compensate those forced to make excess reductions.

ADDITIONAL CONCERNS

PSI has several other concerns about the regulatory proposal set forth as S. 1630.

Making the Trading System Work

PSI strongly supports the bubbling and emissions trading provisions of the bill. An efficiently operating market would substantially reduce the overall costs of compliance, and thus reduce adverse rate impacts. However, the steps in the required permit process, which mandates a written proposal and government approval for changes at individual units, could take many months. Those delays will impede full realization of the bill's cost saving bubbling and trading provisions. A streamlined tracking process for allowance trading is therefore needed so the new market system will work as efficiently as possible.

Furthermore, the bill should do more to protect the future value of allowances. As written, S. 1630 makes it clear that allowances are mere privileges, subject to cancellation at the whim of the EPA. This falls short of the necessary assurances needed to support the open commodity market in allowances hoped for by the bill's proponents. The bill should specify those limited conditions which would interfere with future allowances.

The trading system will more closely resemble a true free market if the geographic limitations on allowance trading are lifted. Localized environmental concerns about increased SO_2 emissions should be addressed through the appropriate state implementation plans and the prevention of significant deterioration program, not the acid rain trading system.

Finally, PSI has some concerns that the allowance trading system will not operate as smoothly as hoped for in the regulated environment of electric utilities. State and federal rate regulators can have a chilling effect on utility sales of allowances if post hoc review of the prudence of these sales is permitted. One solution would be to bar prudence review if the utility can show that the allowances were sold (or purchased) for "market price" at the time of the transaction.

Reasonable Deadlines for Technological Controls

The January 1, 1995 deadline for achieving Phase I reductions presents a severe scheduling problem for many utilities. If the law is enacted in the spring of 1990 and the regulatory process proceeds according to schedule, the utilities' compliance plans will probably be approved no sooner than early 1993, leaving less than two years for the design and construction of major scrubbing units. That schedule will effectively deter use of scrubbers as a Phase I compliance technique. Thus, we support a two-year postponement of the Phase I compliance date for facilities certifying that they will comply using emission control technology.

Targeting the Clean Coal Technology Program

While PSI applauds the clean coal technologies program, we suggest that the funding for the program be expanded and that the criteria for awarding grants be tied more closely to the specific problems of high-sulfur coal use. The impacts of the acid rain requirements will fall most heavily on the Midwestern higher-sulfur coal miners and the Midwestern ratepayers. We believe that the clean coal technology program should be focused especially on developing new technologies that will permit the continued use of the Midwest's abundant and secure energy resources.

Fair Distribution of Phase I Reductions

Absent a generous cost-sharing provision, PSI strongly favors the existing proposal to regulate 107 plants instead of only 20 plants in Phase I. A 20-plant Phase I arbitrarily imposes very substantial and disproportionate compliance costs on only a handful of utilities, and thus is sensible only when coupled with comprehensive cost-sharing. Moreover, the trading system will not work very effectively if there are only 20 potential buyers in Phase I.

Bonus Credits for Excess Reductions

PSI has mixed feelings about the proposal to offer a "bonus" credit for excess reductions in Phase I. As a potential seller of allowances, PSI is encouraged by a proposal designed to promote more than the minimum Phase I reductions. However, when linked to the move from a 107-plant to a 20-plant Phase I, PSI loses much more than it might gain. PSI is also vitally concerned with the "cap-busting" potential of the so-called 2-for-1 option. In sum, PSI would support the issuance of a bonus credit for excess Phase I reductions if attached to a 107-plant bill and if some allowance offset was provided to ensure that the current target for Phase I emission reductions is reached.

Cap Industrial Source Emissions

The bill's present exemption of industrial sources from any acid rain limitations will encourage industry to self-generate its electricity, leaving captive small customers to carry an ever increasing share of the utility fixed costs. Industrial sources, like utility sources, should be required to purchase allowances to cover any increase in emissions, and new sources should be required to purchase allowances for all emissions. There is no justification for requiring utilities to cut down emissions while industrial sources are allowed to eat up environmental gains made by utilities and paid for by utility ratepayers.

Study Application of Title III to Utilities

Finally, the Senate Environment and Public Works Committee deleted a provision from the Administration's proposal that would exempt utilities from regulation under Title III concerning air toxics pending completion of an EPA study of the need for such regulation. It is my understanding that these regulations would effectively require installation of extraordinarily expensive baghouses on all coal-burning utility plants. I concur with the President's position that an assessment of the benefits of such regulation is needed before ratepayers are asked to bear that substantial added cost.

CONCLUSION

As with many pressing national issues, Congress must strike a balance. The balance here is between a clean environment, sound national energy policy and regional economic vitality. On the issue of cost sharing, however, neither the supporters nor the opponents are asking for environmental concessions. The key issues are fairness and adherence to a coherent national energy policy. Will a few utilities and their customers be penalized today for making long-term investments consistent with the continued use of local coal resources and the national interest in energy security? Will they be forced to pay for more than their fair share of required emissions reductions?

I thank you for the opportunity to submit this statement to the Committee on behalf of PSI, its customers and investors. We all appreciate the attention this Committee is giving these issues and we look forward to working with you and the whole Congress to formulate a sensible and equitable solution to the acid rain problem consistent with national energy policy.

January 24, 1990

STATEMENT
OF
MR. RONALD W. WATKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER
NEBRASKA PUBLIC POWER DISTRICT
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON THE ENERGY IMPLICATIONS OF
S.1630, THE CLEAN AIR ACT AMENDMENTS OF 1989

Mr. Chairman, on behalf of Nebraska Public Power District, I am pleased to submit, for the record, our comments to the Committee for review in connection with the hearings to examine the energy policy implications of S. 1630, the Clean Air Act Amendments of 1989. Without a doubt, this legislation is an energy supply measure in that it affects the capacity of the nation's utilities to meet near-term and future energy demands. This measure, ironically, penalizes utilities and their customers in "clean" States.

As currently drafted, S. 1630 will dramatically inhibit the ability of many utilities to meet expected growth in the demand for electricity by severely limiting the capacity utilization of existing plants. More likely, the measure could encourage our nation's reliance on purchases of imported electric power from Canadian utilities and other entities. This legislation could reduce the demand for abundant supplies of domestic coal, and perhaps increase the need for nuclear power plants for future electricity needs.

Mr. Chairman, these supply-side energy policy related issues are in need of careful review by the Committee. As the Committee well knows, long range energy forecasts are always clouded with uncertainty. However, for the near-term, we are quite certain of the energy supply restrictions we would face under S. 1630, as currently drafted. We support the legislation and its goal to reduce acid rain. Nonetheless, we believe that the bill now before the Senate can achieve that goal in a more equitable and more administratively simple manner.

As a partner in Nebraska's agriculture industry, our energy supply capacity greatly influences the economic base of the state. The agriculture community's reliance on coal-generated electricity to meet irrigation and other strategic energy needs is even greater where our hydroelectric capacity can be affected by record low precipitation. Also, as a utility with the good fortune of available low-sulfur coal supplies from the Powder River Basin, we emphasize that this benefit has not come without significant cost to our customers. We have already shared in the cost of reducing national sulfur emissions.

With this preface, I submit for the Committee's consideration some of our specific concerns regarding the Phase Two acid rain control provisions of S. 1630, and we respectfully suggest changes that would correct energy-related imbalances in the legislation.

CAPACITY LIMITS

The pending Senate proposal to amend the Clean Air Act includes "Phase Two" acid rain control provisions that would impose a limitation on the tons of SO_2 and NO_x emitted by a utility. This limitation restricts actual tons of SO_2 and NO_x output in an amount equal to the tons emitted by the amount of coal burned during a "baseline" period. The amount of coal burned is dependent upon the capacity at which the plant operated. Thus, S. 1630 restricts SO_2 and NO_x levels by employing plant-by-plant capacity limitations equal to capacity experienced during a "baseline" period. These limits severely inhibit our ability to meet new and existing energy demand with our current capacity.

For our system, as an example, S. 1630 would require the units at one station to restrict SO_2 output to equal that emitted at a 12 per centum operating capacity factor. Presently, however, this station is operating at about 50 per centum capacity. Another unit at a different station would be restricted to a capacity factor of 46 per centum although it is currently operating at nearly 50 per centum. These limits compare to what is considered a normal operating capacity of 65 per centum or more. Importantly, 65 per centum is often the average annual capacity factor utilized in the economic evaluation of plant construction.

BASELINE

Under section 402(d) of S. 1630, the term "baseline" means the annual average quantity of mmBtu's consumed in fuel during calendar years 1985, 1986, and 1987 for both the SO_2 and NO_x limitations. While averaging is a more fair measure than a one-year "snapshot," absent adjustment, this selection of years does not provide a level playing field for utilities since many were operating below normal capacity during this period. Capacity factors will range from as low as "zero" per centum to 94 per centum for hundreds of "clean" utilities during this baseline period. As a matter of public policy, this "baseline" rewards those utilities employing units operating at normal capacity and penalizes those which, for various prudent reasons, were below normal capacity during the period.

This provision contrasts with section 405(g) the "new plant" provision of the bill that, as a matter of law, imputes a 65 per centum capacity factor, allowing a normal capacity adjustment for new plants but not for existing plants.

UNITS ABOVE 1.20

Under section 405(b) of S. 1630, the "reference year" for determining whether the SO_2 emission rate for a unit was equal to or above 1.20 lbs/mmBtu, is a one-year "snapshot" of the unit's actual 1985 emission rate (NAPAP, Version 2). Since the rate of emissions is a factor in the tons of SO_2 emitted, this one-year snapshot is not a fair measure of a unit's emission rate. This is because rates can vary slightly from month-to-month and year-to-year depending upon the quality of the coal supply at the time. For example, this one-year snapshot can impose an unfair burden for those utilities which, by geologic happenstance, acquired a one-time supply of either less "clean", or exceptionally "clean", low-sulfur coal that produced an uncharacteristically high, or exceptionally low, emission rate.

Averaging emission rates would be consistent with averaging fuel consumption as a better measure.

UNITS BELOW 1.20

Under section 405(d) of S. 1630, the "reference year" for determining whether the SO_2 emission rate for a unit was "clean," that is below 1.20 lbs/mmBtu, is again a one-year "snapshot" of the unit's actual 1985 emission rate (NAPAP, Version 2). As noted above, since the rate of emissions is a factor in the tons of SO_2 emitted, use of this one-year "snapshot" is not a fair measure and the use of a 3-year average in measuring a "reference" emission rate in a manner similar to averaging fuel consumption for the tonnage limit's "baseline" would be more fair.

For these "clean" plants the bill also includes a capacity factor increase of 20 per centum to the 1985-87 "baseline" that only further exacerbates the capacity problems discussed above. The 20% adjustment inequitably rewards some utilities with a capacity factor in excess of 112 per centum and penalizing others with a capacity factor of as low as 15 per centum. This provision discourages the use of existing capacity to meet future energy needs, and contrasts with the provision for all new plants at section 405(g) of the bill that imputes a normal capacity factor of 65 per centum.

CLEAN STATES

Under section 406 of S. 1630, a "Clean States" Credit is provided only to those States: (a) with less than 150,000 tons of SO_2 emitted by utilities in 1985; and (b) in which 50% of coal-fired utility generated electricity produced in 1988 is from "scrubbed" units. This provision excludes and thus penalizes other deserving "clean" states that emitted less than 150,000 tons of SO_2 without the use of "scrubbers," in either 1985 or 1988. For example, Nebraska has maintained statewide SO_2 emissions of less than 50,000 tons (100,000 tons less than this provision) since 1985 without scrubbers. The bill's two-tiered "reference" period for these special "clean" States employs the year 1985 for measuring tons of SO_2 emitted, but not emission rates, and the year 1988 for measuring "scrubber" utilization. Unlike "baseline" standards imposed on other "clean" utilities, the bill employs a three-year averaging of future tons of SO_2 emissions over the period 1996, 1997, and 1998 as the "tonnage cap".

ALLOWANCES

S. 1630 has another serious consequence for utilities and consumers in "clean" states. Under section 403, the bill allows utilities to balance the emission levels among their units, and establish a "bank account" of emission allowance credits by reducing emissions. Furthermore, EPA would maintain a reserve of 2 per centum of all allowances for "auction." The limitations placed on already "clean" utilities under S. 1630, as currently drafted, will not allow many to earn credits and will force "clean" plants to compete for EPA reserves at additional cost to ratepayers.

CONCLUSION

In summary, Mr. Chairman, I emphasize that we are not opposed to legislation that would address the acid rain problem. However, S. 1630 does not provide sufficient flexibility for utilities in those "clean" states, such as Nebraska, that have already invested significant efforts to achieve exceptionally low SO_2 emissions. Modifications to S. 1630 addressing the specific inequities outlined above would make the bill a more consistent "polluter pays" measure. At a minimum, an averaging of emission rates for all plants and an imputed 65 per centum capacity factor adjustment for all "clean" plants under the SO_2 and NO_x provisions is warranted.

As an alternative, however, a more administratively simple approach that would also achieve the bill's SO_2 tonnage reduction goals would be to replace the plant-by-plant standards with a uniform Phase II sulfur emission rate for all plants of perhaps 1.10 lb/mmBtu. Requiring all plants to meet the same standards that many "clean" plants have already achieved or even exceeded would seem to be fair and desirable public policy. Indeed, the U.S. General Accounting Office has cautioned that, absent more data, a Phase II program may be premature and could, for example, inadvertently increase ozone pollution. (See U.S. GAO, "Air Pollution: Improved Atmospheric Model Should Help Focus Acid Rain Debate," November 1989).

Thank you for your consideration of our views on this important legislation.

WRITTEN COMMENTS FOR IOWA SOUTHERN UTILITIES COMPANY,
PREPARED BY ROBERT B. BERGSTROM,
ON THE AIR TOXICS PROVISIONS OF S.1630,
THE CLEAN AIR ACT AMENDMENTS OF 1989
SUBMITTED TO THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
January 24, 1990

Introduction

Mr. Chairman and members of the Committee, I appreciate the opportunity to submit comments to you on the impact Title III (air toxics) of S.1630 could have upon the ratepayers of Iowa Southern Utilities Company.

Iowa Southern is an investor-owned gas and electric utility company that provides electric service to approximately 100,000 customers. Primarily, Iowa Southern service territory is rural and dependent upon small industry, agriculture and agri-related businesses.

Iowa Southern is concerned with the potential economic impact that S.1630 would have on our ratepayers. We believe the economic impact of this bill on the people of southern Iowa could be more severe than any clean air legislation yet proposed.

Iowa Southern will comment on how the air toxic title of S.1630 will apply to one of our jointly owned generating stations, the plants emissions, the control technologies available to control the emissions and the cost which could be passed on to the ratepayer.

Overview of Air Toxics Legislation

Title III of S.1630 will amend Section 112 of the Clean Air Act. Currently, Section 112 requires the EPA to perform a two prong test before labeling a chemical as a hazardous air pollutant. "A hazardous air pollutant" is defined as any "... air pollutant ... which in the judgment of the (EPA) Administrator causes, or contributes to, air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible, or incapacitating illness." 42 U.S.C. §7412(a)(1). Once a substance is labeled a hazardous air pollutant, EPA must establish an emission standard for that substance which allows "an ample margin of safety to protect the public health." Under current regulations, EPA is allowed broad discretion to determine which substances warrant regulation.

At present, EPA thoroughly regulates the emissions of utility power plants under several different sections of the Clean Air Act. For example, utility emissions are subject to National Ambient Air Quality Standards under §109 of the Act. Further, the emissions are subject to state implementation plans under §110 and New Source Performance Standards under §111 of the Act.

In accordance with Section 112 of existing law, EPA has already studied certain toxic substances emitted by electric power plants which are proposed for regulation by Title III of S.1630. EPA determined that the minimal risks of trace emissions of these toxic substances did not pose a risk to the public health which would warrant regulation.

Since §112 was enacted in 1970, only a few air pollutants have been defined as hazardous and had appropriate emission standards set. The slow pace of regulation is due in part to the continual litigation defining health risks.

S.1630 Title III Air Toxics Proposal

If enacted, the air toxics proposal of S.1630 would greatly reduce the discretion of EPA when considering regulating hazardous substances. S.1630, as proposed, would list 191 specific chemicals as hazardous air pollutants and regulate emissions of those substances from each individual source based on technology. In other words, the proposed legislation will revise the two prong test of §112 which determine health risk and establishes a standard. S.1630 will apply control standards and then determine if any health risk still exist.

As proposed, any industrial source which emits 10 tons per year or more of any one of the 191 listed substances or 25 tons or more per year of any combination of listed substances would be considered a "major source". As a major source EPA would require the installation of Maximum Achievable Control Technology (MACT). If, after applying MACT, EPA believes a significant health risk remains, the agency will set a more stringent emission standard depending upon whether the substance emitted is carcinogenic or noncarcinogenic. This approach precludes serious consideration of health risk until the control technology is applied.

Iowa Southern is uncertain as to the exact definition of Maximum Achievable Control Technology. Since MACT does not contemplate a cost-benefit analysis, the control technologies are likely to be more expensive than necessary.

Trace Emissions From an Iowa Southern Power Plant

Of the 191 chemicals listed for regulation, Iowa Southern's Ottumwa Generating Station (OGS) is known to emit 13. There are certainly more but we only tested for 13 chemicals known by analysis to be present. OGS met the new source performance standards when it began commercial operation in May of 1981. OGS is a 725 gross megawatt plant which burns low sulfur Wyoming coal and is equipped with a state-of-the-art electrostatic precipitator with a control efficiency of 99.4%. The sulfur emissions from OGS has historically averaged 0.818 lbs. of sulfur dioxide per million Btu heat input. On average, OGS burns approximately 2.1 million tons of coal per year.

In 1989 Iowa Southern performed a series of mass balanced tests on the ash and coal to determine the weight of the listed chemicals known to be emitted by OGS. A mass balanced test compares the elements present in the coal prior to combustion with the same elements in the ash residues to determine the weight of the chemicals emitted.

Iowa Southern contracted the services of Commercial Testing Engineering Company to analyze the samples of coal and ash collected. Iowa Southern collected two samples each of bottom ash, economizer ash and fly ash for each of the two tests performed. In addition, four samples of coal were collected for each of the tests performed. Commercial Testing and Engineering analyzed the samples according to ASTM, part 05.05.

Test results for each of the chemicals are summarized as follows:

Element		Tons Emitted
Arsenic		1.5
Beryllium		0.5
Cadmium		0.5
Chlorine		1050.0
Chromium		0.5
Cobalt		1.0
Copper		.5
Lead		2.0
Manganese		9.8
Mercury		.5
Nickel		3.0
Selenium		2.0
	Total	1071.8

On June 22, 1989, I disclosed the results of these tests in testimony before the United States House of Representatives Subcommittee on Health and Environment. Further, the test results have been shared with the EPA in Washington, the EPA staff at Research Triangle Park in North Carolina, and the staff at the Department of Energy. Both EPA and DOE are in general agreement with our test results.

Chlorine is an anomaly. Neither EPA nor the Electric Power Research Institute (EPRI) were aware that chlorine would be emitted in this amount from low sulfur coal. According to EPRI, chlorine is emitted primarily as hydrochloric acid which can best be controlled by the use of a wet scrubber or spray dryer.

Installation and operation of such control equipment would be extremely expensive. For example, according to EPRI the approximate cost of a wet scrubber for OGS to control chlorine would be in the range of 150 to 180 million dollars.

Comparison of H.R.3030 and S.1630

Very little scientific evidence is available to indicate if a health risk is associated with the trace amounts of chlorine emitted from a utility power plant. In recognition of this inconclusive scientific evidence, the Administration included a provision in its proposal, H.R.3030, which required the EPA to perform a study of the hazards to public health which might exist as a result of emissions by electric utility steam generating units. The Administration's proposal required the EPA to conduct a three year study identifying the risks and describing alternate control strategies for trace emissions which could warrant regulation. The EPA was not allowed to regulate utility emissions unless the regulation was appropriate and necessary after considering the health risks associated.

However, in S.1630, a similar provision requiring a study is absent. S.1630 only prohibits the Administrator from promulgating a standard with respect to the emissions of chlorine compounds emitted from utility steam generating units for three years after enactment of the bill. Unfortunately, this would only delay regulation of chlorine emissions through a technology based approach until three years from enactment. This provision does not require a study to determine what, if any, health risks are associated with the emission of chlorine and chlorine compounds.

Most important, S.1630 is silent as to the other emissions from utility steam generating units. Therefore, EPA will be allowed to proceed and impose technology based reductions on emissions other than chlorine and chlorine compounds.

Impact of S.1630 on Iowa Southern and Other Utilities

As mentioned above, coal fired utility power plants emit several types of pollutants listed in S.1630 in trace amounts. Trace elements in coal vary with each shipment from the mine, so the ultimate amount of emissions is hard to estimate. But without question, our company and other companies burning coal will emit these elements in trace amounts at times below and at times slightly in excess of the 10 ton - 25 ton limit. In short, at these low levels of detection we are always going to be "on the margin" of the limits.

If coal fired power plants must comply with the acid rain and air toxic regulations envisioned in S.1630, the impact on ratepayers will be significant. For at least some of the chemical substances listed in S.1630 control technology does not exist. For other emissions, when control technologies do exist, they are extremely expensive. Dry or wet scrubbing of a power plants emission can control some of the substances listed in the bill, but not all. If Iowa Southern must install wet scrubbing equipment at all the company's generating stations, a rate increase to our customers in the range of 25 to 30 percent will be necessary.

A 25-30% increase in electric rates is significant and it will be a serve hardship for the elderly on fixed incomes, the unemployed and the working poor. Many of these people tend to live in housing which is not energy efficient, so unfortunately, they already pay a disproportionate share of their income on energy. An increase in electric rates comes at a time when Congress has cut funding for the Low-Income Energy Assistance Funds (LIHEAP) designed to assist the poor with their energy expenses.

Iowa Southern works closely with the Community Action Programs (CAP)s in the Company's service territory. The CAP agencies deliver a variety of social programs to the poor, the elderly and the disadvantaged. The CAP Directors were informed of the potential rate increase and were asked to comment. Below are excerpts from their comments:

> "...[A] 28% increase in residential rates would be disastrous for many of our low income clients served by the South Central Iowa Community Action Program. Our low income energy assistance programs serve 3,545 households. Of this number, nearly 2,500 households had incomes at or below the 100% poverty [level] ... 1,400 of these households are comprised of persons aged 60 or over and are on fixed incomes.
>
> This legislation will be really harmful to our area and not only to our low income [clients], but, we're not going to be able to keep the industries here that we need. I do a needs assessment every year ...

and my number one priority ... is jobs and employment. If you had enough jobs and enough employment you wouldn't have any poverty ..."

Clyde Taft, Executive Director
South Central Iowa Community
Action Program

* * *

"If [S.1630] ... is passed, the impact would be tremendous for all households, especially the low income and elderly. The Federal Government has chosen to vote to reduce the allocations for the Low Income Home Energy Assistance Program, so that more households are now being served on less money. The allocations for the State of Iowa show the following reduction with the increase of household need:

Funding	Households Served
1983 - $36,719,800	91,725
1988 - $28,504,175	102,392

The State of Iowa shows 102,392 households were unable to meet their utility ... obligations without other assistance. Heat is not a luxury in our state, but a critical need. An additional 28% [will make] the elderly and low income ... again the loosers ..."

Linda Keller, Executive Director
Red Rock Area Community Action
Program

* * *

"Congress has been reducing the energy assistance money that they are making available to agencies such as ours for fuel assistance payments. If, [S.1630 is enacted] not only would our clients be faced with a reduced payment, but also an increased fuel bill ... this is critical for our area when you look at the number of people that are on fixed incomes. 25% of our population in this are average 65 years of age or older. They are dealing with retirement incomes and social security. These people cannot realistically expect to have someone hire them so as to supplement that income..."

Phyllis McWilliams, Executive
Director, Southern Iowa Economic
Development Association

Iowa Southern is also concerned with attracting and maintaining business and industry. Iowa Southern informed the 20 largest electric industrial customers of the potential rate increase and solicited their responses. The following profiles are actual responses from the management of these companies. However, due to the sensitive nature of this business information, Iowa Southern provides only a brief profile of the community, the nature of the industry and the amount and size of the payroll.

> A top management official with an auto component part manufacturer, in a city of 30,000, that employs approximately 230 people with an annual payroll of 7.5 million dollars, stated: "... the Iowa plant is our most productive plant. We believe its success is due to two factors. First, the strong work ethic that the people of Iowa possess, and second, we enjoy low utility rates. If the cost of electricity rose 28%, we would give serious consideration to relocating elsewhere..."
>
> * * *
>
> A senior executive for a plastics manufacturer, in a city of 7,000, that employs approximately 300 people with an annual payroll of 7.78 million dollars, stated: "...energy costs are the company's second highest expense - behind raw materials. If the price of electricity was to increase 28%, we would relocate to Oklahoma where we have another plant ..."

Potential Contradicting Overlap in Title III and Title IV of S.1630

This Committee should take note of the potential overlap in legislation to control air toxics and efforts to control acid rain precursors. The work by this Committee and others to draft an acid rain bill which will allow the utility industry freedom to choose the proper compliance method, would be wasted if the air toxics legislation required most, if not all, coal fired utility boilers to scrub.

The potential for contradicting and overlapping environmental legislation which effects the reliability of the electric energy on which this nation so heavily depends, points out the need for a comprehensive energy-environmental policy. Unfortunately, it appears the prospects of a comprehensive approach towards matters involving environment and energy are not good.

The utility industry can reduce the emissions of some air toxics but the reductions will be made at an enormous cost. A cost benefit analysis pertaining to air toxics is the only proper way to look at this proposed environmental-energy legislation.

As a nation, we should ask these questions: Are reductions in air toxics from utility plants necessary? Are there any benefits? If we should make emission reductions of air toxics, what are the most cost effective methods of realizing the benefits?

It is possible that questions may be asked, but will we wait for the answers? If current events are a guide, the answer is no.

For today, concurrent with these hearings the Senate is debating legislation to control acid rain. Unavailable for the debate is the final report of the National Acid Precipitation Assessment Program (NAPAP), which is due in October. NAPAP is a multiple disciplinary, ten year, six hundred million dollar Congressional study conceived and co-sponsored by Senator Daniel Patrick Moynihan. NAPAP's mission, which it is about to complete, will assess and define the acid deposition problem utilizing the best scientists and research facilities available.

NAPAP's very existence suggests the nation is willing to ask the questions: Are further reductions of SO2 necessary? Are there benefits? What are the most cost effective methods available to realize those benefits? In regards to acid rain, Congress should have waited for the answers. Our fear is Congress may not even ask for the scientific evidence on air toxics before mandating expensive controls.

Conclusion

Iowa Southern would support legislation which would eliminate the need for excessive litigation and thereby improve the time necessary to set standards for protection of the public health and environment. However, we are concerned the proposed legislation will place too much emphasis on technology based controls without consideration of feasibility, cost or necessity of control.

Title III of S.1630 will fundamentally change the EPA's approach to regulating air toxics which is likely to result in premature and expensive legislation. To ensure the best environmental results of the lowest cost, Congress should await the NAPAP report to avoid needless overlapping laws. At this time, Iowa Southern cannot support this Amendment as written.

The utility industry's trace emissions of toxic substances should be subjected to a full and complete study to determine possible health risks, if any, to consider the feasibility of control technologies and to consider cost. Such a study should be undertaken prior to regulation of trace emissions from fossil fuel fired utility boilers.

Last, Iowa Southern respectfully submits that it is prudent to look at all environmental-energy legislation in a comprehensive manner to better serve the nation's interest. Such an approach could enhance electric energy reliability and provide for better protection of the environment at lower cost.

STATEMENT OF

THE

NATIONAL COAL ASSOCIATION

HEARINGS ON

THE CLEAN AIR ACT AMENDMENTS OF 1989

before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

JANUARY 24 - 25, 1990

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

HEARINGS ON
THE CLEAN AIR ACT AMENDMENTS OF 1989

STATEMENT OF THE NATIONAL COAL ASSOCIATION

JANUARY 24 - 25, 1990

This statement is submitted for the record on behalf of the National Coal Association. National Coal Association (NCA) is an organization which represents producers of coal from the smallest to the largest. NCA members, which comprise the majority of coal production in the United States, operate in all producing regions of the country and mine all qualities of coal. The association appreciates the opportunity to express the coal industry's views on the acid rain proposals now pending before this committee and the Senate.

Make no mistake, the coal industry supports the goals of cleaner air. Our industry, in conjunction with our major customer the utility industry, has worked hard over the past two decades to achieve this goal through compliance with the standards set out by the current Clean Air Act as amended. These efforts have paid off. As the Environmental Protection Agency (EPA) has stated: "the data clearly shows that over the long term the Clean Air Act has worked well in reducing pollution . . ..." [1]

We firmly believe however, that environmental goals must be founded on sound science and that they must be reasonably balanced with the equally important goals of energy security and economic growth. We do not believe that S.1630 as reported out of the Senate Environment and Public Works Committee offers that balance.

We know that the President and his Administration recognize the importance of balancing these goals to the future of our nation as demonstrated by the current effort of the Department of Energy to complete a National Energy Strategy. This study and its recommendations, which are being prepared with broad input from all sectors, should be the cornerstone of our attempt to find that required balance between energy, economics and the environment.

Unfortunately, the acid rain proposals now pending are in direct conflict with this work. Instead of coordinating with and complementing a reasonable energy strategy -- and the policies that should flow from a well considered plan -- amendments to the Clean Air Act as now drafted predetermine our energy policy.

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[1] "National Air Quality and Emissions Trends Report, 1987" The U.S. Environmental Protection Agency, 1989.

Most proposals to amend the Clean Air Act, taken in their entirety, would also become the de facto industrial policy of the United States as the regulations, controls and costs that would be placed on industrial operations will have a significant effect on determining the international competitiveness, levels of output, locations of businesses, and total employment in all affected industries.

This committee, and the entire Senate, must consider the effect the various acid rain proposals will have on the potential for economic growth and stability and on the United States international competitiveness. The fundamental re-ordering of a large part of America's industrial base which is suggested by these proposals should not be decided - or even debated - without the benefits of an extensive analysis of its effects on all these factors.

One such study has just been completed. On January 18, 1990 The Business Roundtable released a study that estimates the total cost of the Senate Clean Air Act amendments now being considered range at $54 billion to as much as $104 billion annually. The acid rain provisions alone will cost from $3 to $8 billion annually. The Congressional Budget Office, the Office of Technology Assessment and the Congressional Research Service have been asked by over 40 Senators for a similar cost and economic analysis. Consideration of the bill should wait until the results of this work are available.

Beyond the reason of conflict with Administration efforts to develop a national energy strategy and the fact that the economic analysis requested by the Senate has yet to be completed, acid rain legislation should not be rushed through the Congress for two reasons:

. First, the results of the 10 year research program conducted by the Congressionally mandated National Acid Precipitation Assessment Program (NAPAP) [2] to determine cause and effect of acid rain are beginning to emerge and will be available in their entirety in September, 1990. In 1987, NAPAP's Interim Report concluded that we do not face an environmental crisis that demands precipitous action. The final report, which will be a comprehensive integrated assessment on the causes and effects of acidic deposition, combined with analyses of the costs and effectiveness of various emission reduction strategies may support a course of action that differs significantly in cost and approach from those suggested in the proposals now pending.

. Second, as numerous private industry and government studies have shown, with respect to sulfur dioxide, the Clean Air Act is working. Sulfur dioxide emissions from power plants and other industrial stationary sources have declined significantly since enactment of the original Clean Air Act. Commercialization of the clean coal technologies now being developed will result in an equal or greater amount of emission reductions at significantly lower cost than would legislation that mandates specific technology and/or a sharp emissions reduction within a very short period of time.

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[2] The Interim Assessment of the National Acid Precipitation Assessment Program, November, 1987,

COMMENTS ON ACID RAIN PROPOSALS NOW PENDING BEFORE CONGRESS.

NCA strongly opposes enactment of the acid rain proposals included in S. 1630 which is now pending before the Senate. The "Clean Air Act Amendments of 1989" would, if enacted, effectively set the direction of future energy policy of the United States and would make our goal of balancing energy security and economic growth with environmental protection much more difficult.

As this committee is well aware, adequate and reasonably priced energy supplies are imperative to sustain long term economic growth. In the United States, coal is an integral part of that energy supply and is expected to continue over the long run as a primary energy feedstock.

Coal accounts for almost 80 percent of our nation's fossil fuel resources, is 32 percent of domestic energy production and provides nearly 25 percent of the total energy required in the United States today. Of particular importance to today's hearing, over half the electricity produced in the United States, 57 percent, is generated by coal. If oil instead of coal had been used to generate that electricity in 1989, the United States would have had to more than double our oil imports with a cost to our balance of payments of over $46 billion and a net cost to the economy of over $23 billion dollars.

But energy supplies and thus energy security and continuing economic growth are vulnerable on two fronts: through the continuing increase in dependence on imported energy and from pending shortages in electrical generating capacity.

Our dependence on imported energy is rapidly increasing as illustrated in the December, 1989 statistical report of the American Petroleum Institute. This report stated that total imports of oil in 1989 reached a ten year high of nearly 8 million barrels per day while domestic production was at the lowest level since 1965. Adjusted for stock changes, imports share of the market in 1989 was 46.7 percent - an all time high.

This trend will continue. The Department of Energy projects a 55 percent dependence on imported oil by 2000. [3] It goes without saying that the fiscal and balance of payment ramifications of imports of this magnitude will have a significant, and negative, effect on our economy.

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[3] 1989 Annual Energy Outlook, Long Term Projections, Energy Information Administration, Department of Energy, January, 1989. Base case estimates are cited throughout this statement. (Please not that the AEO will be updated in late January or early February, 1990.)

Of equal importance to maintaining the future economic health of the nation is the probability of regional shortages of electric generating capacity as the economy becomes dependent on reasonably priced electricity to meet end use energy needs. To illustrate this trend, in 1976, electricity met 29 percent of end use energy consumption needs. In 1989 this figure was almost 36.5 percent. B by 2000, DOE projections show that 42 percent of end use energy requirements will be met with electricity.[4]

Reasonably priced electricity over the past decade has meant economic growth and an improvement in the competitiveness of U.S. manufactured goods, both at home and abroad. Since 1980 our GNP has increased - in real terms - by over 26 percent. According to the Department of Commerce the f.a.s. value of our merchandise exports (in 1982 dollars) almost tripled from 1982 to 1988. These accomplishments mean jobs, they mean a rising standard of living. Without reasonably priced energy and readily available electricity the accomplishments of the past cannot continue.

It is well documented that for each percentage increase in GNP there is an approximate one percent increase in the demand for electricity. While that relationship may be altered in the future due to conservation and demand management by utilities, economic growth will still require an increase in the use of energy, i.e. electricity.

In early 1989 both the Department of Energy and the Edison Electric Institute released reports which forecast that demand for electricity will increase at an average annual rate of 2.4 percent between 1988 and 2000.[5] These demands cannot be met with current and planned generating capacity. A report issued in late September 1989, by the National Electric Reliability Council [6] shows that utilities are planning to add approximately 72,200 MW of new capacity between 1989 and 1998. This includes 18,100 MW from non-utility generators -- most of which is not yet under construction. This new capacity is onlv sufficient to handle than a 1.5 percent annual growth in electricity demand over the next decade and causing NERC to conclude:

> "While aggregate utility plans will support the forecast growth in peak demand, there is a widespread trend of actual peak demands consistently exceeding forecasts. If this trend continues, supply deficiencies are likely by the early 1990's in the eastern half of the United States and Canada."

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[4] This estimate represents only the electricity produced and/or distributed by electric utility companies. Therefore, the estimate of dependence on electricity understates the total due to power requirements met by industrial self-generation.

[5] DOE - 1989 Annual Energy Outlook; the Edison Electric Institute, Electricity Future: America's Economic Imperative.

[6] 1989 Reliability Assessment The North American Electric Reliability Council, September, 1989.

Unnecessarily restrictive legislation could exacerbate these shortages and make it much more difficult and costly to meet energy/electricity needs in the future.

Where does coal fit into the picture? Coal, which generates 57 percent of all the electricity produced in the United States, has kept electric rates down. This is a major reason that manufacturing plants in the midwest and south - which account for over 25 percent of our export activity have become more competitive at home and internationally. If S.1630 is enacted, electric rates will rise sharply not only in these coal dependent areas but over the entire United States, eliminating the competitiveness that has been gained over the past few years. This would cost manufacturing jobs and jobs in support industries. Energy intensive manufacturing, such as aluminum, would move offshore and be permanently lost.

Several supporters of acid rain legislation have stated that the increase in electric rates that would be precipitated in the industrial heartland of America would not be harmful since rates in these manufacturing dependent areas are now significantly lower than those in the remainder of the country. They argue that S.1630, and other clean air act proposals, would only "level out" rates throughout the nation. We believe that such a philosophy is counterproductive to our nation's competitive performance potential in the international marketplace.

We believe that rather than increasing electric rates in the states that comprise our industrial base, we should be enacting a national energy policy to decrease electric rates and energy costs throughout the United States. Our goal should be a nation- wide increase in the use of lower cost coal with more efficient clean burning technologies - which would avert sharp increases in all electric rates.

The development of modern technologies means that coal can be extracted, transported and burned in an environmentally benign manner. Coal is available over the long term. New technologies to use coal increase conversion efficiencies. The use of coal is cost effective in both the short term and over the longer run. Coal means reasonably priced electricity, coal means that the United States is competitive in the world market. In short, coal is a primary component of our nation's energy and economic future.

With this prelude, let us discuss several of the critical issues raised by acid rain provision pending before the Congress.

REQUIRED EMISSION REDUCTIONS WILL BE OVER 12 MILLION TONS

The predominant premise of acid rain legislation is to effect a 10 million ton per year reduction in SO_2 emissions by the year 2000, measured from a 1980 base. Although advertised as a "10 million ton reduction bill", both the President's proposal, S. 1490, and S. 1630, will result in greater reductions. Neither bill fully recognizes either emission reductions made by the utility sector since 1980, or the 2.7 million ton emissions reduction that was made in the industrial sector between 1980 and 1985. Additionally, the proposals give no credit to the potential for additional emission reductions which will occur in the industrial sector before 2000.

A recent Edison Electric Institute [7] analysis on the President's proposal shows that utilities alone will be forced to reduce emissions by almost 10 million tons by 2000 as measured against 1980 levels. NCA's analysis of the industrial sector which, according to NAPAP has already reduced SO_2 emissions by 2.7 million tons from 1980 thru 1985, shows that we can conservatively expect an additional 1.1 million tons reduction from industry by 2000 for a total reduction by industry of 3.8 million tons, 1980 - 2000. Under the guidelines now under consideration, by the year 2000 SO_2 emissions from all sources could be almost 13.5 million tons lower than in 1980, far in excess of the President's stated 10 million ton goal. [8]

To our knowledge there is no scientific basis, in terms of environmental impact or benefits, for either a year 2000 compliance date or a 10 million ton reduction goal, to say nothing of one that is greater. However, it is beyond dispute that the magnitude of the reduction requirement over the compressed time frame will disproportionately escalate the cost of the compliance program. According to the Edison Electric Institute report cited above, scaling back requirements to match the stated 10 million ton goal would reduce costs of compliance by at least 30 percent.

A complete analysis of the actual emissions decline since 1980 shows that extension of the compliance time frames now proposed, and a reduction of the emissions target - through elimination of the proposed tonnage cap on emissions from existing plants and elimination of the offsets proposed for new capacity - are clearly possible without jeopardizing a 10 million ton reduction goal.

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[7] "Economic Evaluation of H.R. 3030/S. 1490 Clean Air Act Amendments of 1989, Title V, The Acid Rain Control Program". Edison Electric Institute by Temple, Barker and Sloane, Inc., August 30, 1989.

[8] To summarize the results of this analysis (the industrial analysis is included in its entirety in Attachment A):

	1980	1985	Tonnage Change 1980-1985	2000	Tonnage Change 1980-2000
	(SO_2 Emissions	- 000 tons)			
Electric Utilities	17,479	16,178	(1,301)	7,779	(9,700)
Industry	9,476	6,836	(2,641)	5,711	(3,765)
Total	26,955	23,014	(3,941)	13,490	(13,465)

Source: 1980, 1985 NAPAP Emissions Inventory, Version 5.0
2000: Electric utilities - Edison Electric Institute, Industrial, NCA Estimates, see Attachment A to this statement.

The widely recognized NAPAP inventory for 1980 should be used as the base from which sulfur dioxide emission reductions are measured and the legislation should so state. Use of this base would result in a true 10 million ton emission decease by 2000. An initial phase reduction of any legislation should set a target that gives full credit for the reductions made by the industrial sector since 1980.

THE CAPS PLACED ON EMISSIONS FROM CURRENTLY OPERATING PLANTS MUST BE ELIMINATED.

S.1630 requires units emitting greater than 1.2 lbs. SO_2/MMBTU to reduce their effective emissions rate to one that is below the current, and accepted, NSPS standard of 1.2 lbs. SO_2/MMBTU. This is accomplished by placing a cap on SO_2 emissions from existing[9] power plants that, after 2000, will be equal to the product of the baseline[10] fuel use in millions of BTU's times the maximum rate of 1.2 pounds SO_2/MMBTU. Units emitting at a rate less than 1.2 lbs. SO_2/MMBTU in 1985 would be capped at a tonnage amount equal to their 1985 average annual emissions rate times the baseline times 120 percent. Finally, new plants are limited to operating at a 65 percent capacity factor.

The tonnage cap effectively precludes full utilization of units at affected utility plants if the baseline represents a period of low or medium generation unless emissions are at a much lower rate than 1.2 lbs. SO_2/MMBTU, the accepted NSPS standard. Various estimates have put the effective rate that the many utilities must meet at less than 1.0 lbs. SO_2/MMBTU -- and, where strong growth in expected, as low as 0.3 lbs.

The tonnage cap for existing NSPS plants, even given the additional credits allowed by the 20 percent growth factor, will force "clean plants" to install additional controls. Plants constructed under NSPS standards, i.e. those emitting less than 1.2 lbs. SO_2/MMBTU, could be forced to retrofit with technological controls (if feasible) or to fuel switch (if possible) to insure that the plant's actual emissions, especially in an area of growth, does not exceed allowable.

Finally, as new plants are always the most efficient, cleanest and capable of being operated at high capacity factors, S. 1630 is counterproductive in limiting use of those clean plants to 65 percent.

The tonnage caps on utility plants will sharply increase costs of compliance and will sharply reduce the flexibility that a utility has in managing its resources and in meeting unexpected levels of demand. It is very probable that given an unexpected short term increase in demand, such as occurred in 1988, a utility system that is predominantly coal-fired could approach the end of a year faced with some hard choices: shut down capacity or pay exorbitant fines on excess emissions -- which will have to be offset in the next year.

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[9] Existing is defined as a utility unit in operation at the time the bill is enacted.

[10] Baseline is the average BTU of fuel consumed at unit during the 1985-1987 period.

The fact that the cap increases compliance costs is clearly shown in the EEI report referenced earlier. EEI's analysis showed that 44 percent of the costs of compliance with S.1490, the President's proposal, will be in the states of Ohio, Pennsylvania, Indiana, Missouri and Tennessee. A full 70 percent of compliance costs will be incurred in those five states plus Alabama, Georgia, Illinois, Kentucky and West Virginia. The costs of electricity to customers will increase from 9 to 22 percent. These states are the location of over 30 percent of our manufacturing activity (measured in contribution to the national GNP). Over 25 percent of our exported manufactured goods were produced in these states. Clearly, the additional costs incurred under S.1490 will result in a decline in the international competitiveness of these industries and will result in lower output and loss of jobs in the manufacturing sector.

The tonnage caps should be eliminated and replaced with a rate cap no lower than the permitted standard for NSPS plants. There should be no limit on use of new plants. These standards would achieve over a 10 million ton reduction from 1980 SO_2 levels and permit utilities to significantly reduce rate impacts on their customers and service areas. This would provide flexibility in meeting future growth in the American economy and would ameliorate adverse impacts in all effected areas.

THE REQUIREMENT TO OBTAIN OFFSETS FOR NEW GENERATION SOURCES WILL PLACE AN ABSOLUTE LIMITATION ON COAL USE.

Proposed legislation requires all new coal-fired generating units to obtain offsets equal in amount to the tons of SO_2 that the new source will emit. Although offsets will be available from retirement of some capacity, retirement credits will not be sufficient to support long-term growth in coal-fired generation. The EEI report finds that retirement credits would only be sufficient to meet new demand if electricity increases at an annual average rate of less than 2 percent per year and non-coal units provide two-thirds of the new generating capacity required. Both are unlikely assumptions.

The offset requirement will be especially detrimental to utilities in the West and Southwest which are the two fastest growing regions of the country and represent more than half the new coal fired capacity projected to come on line thru the end of the century. Most utilities in those regions have new NSPS plants and will have few credits to use to offset emissions from new capacity.

Further, the offset requirement will preclude the use of coal in non-utility generating units (NUGS) which have been projected to play an increasing role in the nation's power generation mix. Although a NUG will have to comply with applicable NSPS requirements, a NUG must still obtain the necessary emission credits to operate. Utilities might be reluctant to provide credits if the NUG is viewed a "competitor". The elimination of coal as a practical option to the non utility generator will unnecessarily increase the cost of electricity in many areas and significantly restrict this emerging power generation option. Again, the ramifications carry over to the policies now being developed to structure a future that is economically sound and energy secure.

Although S. 1630 provides a small "pool" of credits available for purchase by utilities and non-utility generators alike, we question the ability of NUG's to obtain sufficient long term credits to satisfy the requirements of the financiers of such coal fired projects.

Simply put, the offset requirement forces new capacity decisions away from coal to natural gas. While this appears to be the clear purpose of the drafters of S.1630 and other acid rain proposals, we have not found supporting analysis for such policy.

As pointed out in the preceding section, neither the emissions offset or the emissions cap requirements are necessary to achieve and maintain a 10 million tons per year reduction in SO_2 from a 1980 baseline. Both should be eliminated.

THE PROPOSED TRADING SYSTEM IS UNLIKELY TO ASSIST IN MEETING FUTURE ENERGY - ELECTRICITY REQUIREMENTS

Supporters of both the emission tonnage cap and the offset requirements maintain that the proposed emissions trading system will solve the problems. There are some questions regarding this position. As DRI has pointed out,[11] the proposed trading scheme has a number of regulatory and legal obstacles in its path. The requirement to obtain permits for each trade - and each change in plans to trade - eliminates any flexibility that the trading system might provide. The regulations for the trading system will not be promulgated until 18 months after enactment of the bill. This is only a few months before the utility must have its compliance plan in place for Phase One. Clearly there is insufficient time to factor trading into any compliance plan.

A utility is unlikely to sell an emissions allowance to any other generating source, especially one outside its own system, if there is any possibility that the allowance will be needed in either the short or the long-term. It will be necessary for a utility dependent upon coal-fired power to "bank" emissions credits to use if demand has been underestimated for a given period and generation/emissions are higher than the utility's current allowance. What explanation would a utility give a public commission and rate payers if a credit which sold for X dollars today had to be repurchased for twice, or ten times that amount at a future date?

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[11] "Implications of the Bush Administration's Proposed Clean Air Act Amendments: Phase 1 Acid Deposition Requirements", DRI/Mc Graw Hill Coal Planner, Summer, 1989.

CURRENT ACID RAIN PROPOSALS WILL DISCOURAGE THE USE OF CLEAN COAL TECHNOLOGIES

Clean Coal Technologies (CCT's) are critical to the nation's future. Proposed legislation and regulation must provide time frames that are flexible and that give sufficient time for utilities, and other electric generating concerns, to use the technologies now being developed both under the U.S. Government/Industry Clean Coal program and under programs supported by states and private industry. The use of clean coal technologies means that reductions in emissions will be greater in the long run, and will be achieved at less cost than under a program that legislates short time schedules and, possibly, mandates technologies.

An unreleased study for the Department of Energy [12] illustrates these points. According to this study, SO_2 emissions from utilities are some 75 percent lower in 2030 under a "no acid rain legislation" scenario that allowed penetration of Clean Coal Technologies (CCT's) than would be the case if acid rain legislation were enacted. (The analysis was based on S. 1984 reported by the Senate Environment and Public Works Committee in 1988.) The level of emission reduction achieved with CCT may begin at a slightly later date, but is much more permanent. Further, clean coal technologies are less expensive to the rate payer. Under a CCT scenario average real electricity rates in 2030 will be lower by some 15 percent than under acid rain legislation due, in part, to the increased conversion efficiencies of CCT's.

The real benefits of CCT will not be seen until between 2005 and 2010 when the newer technologies have been deployed. CCT's have other advantages that contribute toward both energy security and economic goals as well as the environmental. Utilization of CCT's ensure that the full range of the United States coal reserves can be used. Conversion efficiencies, as shown in the tables appended to this statement, can be as much as 6 percent to over 50 percent more efficient than a plant with current day technology, i.e. a scrubber. The improved conversion efficiencies will contribute towards lower energy costs and at the same time, address the SO_2, NO_x and CO_2 issues.

NCA is concerned that the broad market penetration of CCT's will not be possible under S.1630. S. 1630 includes a few of the provisions for clean coal technologies as recommended by President Bush and embodied his, S 1490. However, several of the important provisions of S. 1490 are not included in S.1630. Specifically, S. 1490 included a Federal Energy Regulatory Commission initiated five year demonstration program to provide certain, enumerated rate regulatory incentives for several clean coal projects. S. 1490 also included an important exemption from several environmental reviews for those clean coal technologies eligible for the deadline extension or those clean coal technologies selected under the on-going DOE clean coal program.

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[12] "The Macroeconomic Impacts of Clean Coal Technologies and Acid Rain Legislation: A Comparative Analysis," Argonne National Laboratory for the Department of Energy, DRAFT, June, 1989.

These provisions need to be included in any clean air amendments considered. Additionally, Congress should:

> 1) Support an extension of time for Phase Two installation of clean coal technologies until at least 2005 rather than the current proposed extension of 2003. This extra time will encourage the commercialization and deployment of these technologies, and maintain them as an option for reducing sulfur emissions.
>
> 2) Support the use of currently available CCT's for units impacted by Phase One requirements and by providing an extension of time for Phase One plants choosing CCT to meet the applicable requirement for Phase Two. The technologies eligible for such extension, including retrofit technologies, should be named by DOE;
>
> 3) Provide flexibility in the determination of technologies eligible for inclusion in the Phase Two extension by charging DOE with the task of designating technologies that can be used under this bill and with reviewing and updating the list on a periodic basis; and,
>
> 4) Support an extension of the benefits and incentives suggested for repowering with CCT to new greenfield plants.

Finally, NCA is concerned that the failure to exempt so-called "retrofit" technologies from New Source review under the "WEPCO Interpretation" may well preclude utilization of technologies which do not achieve a 90 percent reduction but promise to achieve more cost effective reductions than existing technologies in utility compliance plans. The "WEPCO Waiver" for CCT demonstrations under the DOE program should be expanded to all applications of CCT's.

In conclusion, I would like to review two basic reasons that we continue to believe that acid rain legislation of any type is premature at this time. Both merit the Subcommittee's attention.

IT WOULD BE PREMATURE TO ENACT LEGISLATION WITHOUT THE BENEFITS OF THE 10 YEAR RESEARCH PROGRAM CONDUCTED BY THE CONGRESSIONALLY MANDATED NATIONAL ACID PRECIPITATION ASSESSMENT PROGRAM

It would be premature to enact legislation without the benefit of the results of the 10 year research program conducted by the congressionally mandated National Acid Precipitation Assessment Program (NAPAP). This study was initiated because Congress recognized the many scientific uncertainties that existed concerning the acid rain issue and because Congress realized that it could not rationally address the subject until major scientific gaps in our knowledge had been closed.

The $500 million NAPAP study involves almost 1000 scientists from 40 universities in the United States, Canada and Great Britain, 12 federal agencies, four national laboratories and various other research institutes. NAPAP will conclude in September, 1990 with the publication of a comprehensive integrated assessment on the causes and effects of acidic deposition, combined with analyses of the costs and effectiveness of various emission reduction strategies.

The results of the NAPAP Assessment are just now beginning to emerge and will be available in their entirety within the next year. The acid rain legislation now pending prejudges these results and the scientific studies, technology evaluations and economic analyses - including the planned analysis of the President's proposed legislation [13] - that will be included in the final reports.

Of particular importance for this debate is the interim assessment that was published in late 1987. This report invalidated much of the speculation that projected catastrophic damage to the environment. The study concluded that:

> "While some lakes and streams in sensitive regions appear to have been acidified by atmospheric deposition at some point in the last 50 years, the data currently available suggest that most watersheds in the glaciated northeast are at or near steady state with respect to sulfur deposition and that further significant surface water acidification is unlikely to occur rapidly at current deposition levels."

These 1987 findings were substantiated by a report released by NAPAP in late August, 1989 [14] which finds that future reductions in SO_2 could improve damaged lakes in the Northeast but, if emissions remain constant, lakes will not incur additional damage.

The Interim Report also concluded that: unexplained forest damage is very limited and acid rain is not now thought to be the cause. Importantly the 1987 data found that "the risk of human health effects from airborne sulfur compounds is being managed by ongoing control programs that cap ambient concentrations."

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[13] For a complete description of all the emissions reductions cases to be analyzed by NAPAP see section 2, "Assessment Plan Update", NAPAP, August, 1989. The document also includes a schedule for the release of all portions of the final NAPAP Assessment.

[14] "Future Effects of Long-term Sulfur Deposition on Surface Water Chemistry in the Northeast and Southern Blue Ridge Province: the Direct/Delayed Response Project", August, 1989, NAPAP.

These points have been substantiated by subsequent NAPAP materials which conclude that under a constant SO_2 emissions scenario little change will occur in Northeast lakes; that since forest damage is not caused by acid rain there will be little change under the same scenario except over a 50 year period at very high elevations; that no changes in crop yields are expected under a constant emissions scenario; and that there would be no change in human health effects from that seen at the current time.

NCA would like to point out that the conclusions presented both in the interim report and in later documents published by NAPAP are directly opposite the "findings" included in Title V of S.1490, Sec. 501 (a)(1) which states "the Congress finds that the presence of acidic compounds and their precursors in the atmosphere and in deposition from the atmosphere represents a threat to natural resources, ecosystems materials, visibility and public health."

Data developed by NAPAP suggest that sulfur dioxide emissions comprise only one-third of the emissions considered to be acid rain precursors. NO_x and VOC emissions must be addressed as well and will be the subject of NAPAP assessment. Further, there are indications that the interaction between these emissions, not the quantity of individual emissions may be a key factor in determining environmental impacts.

Since NAPAP scientific data has demonstrated that we are not facing an environmental crisis that demands precipitous action, we believe it is not prudent to enact costly emission control legislation without the benefit of the NAPAP research efforts and analysis of control strategy options. Indeed, it is quite likely that the NAPAP report will support a course of action that differs significantly, both in approach and cost, from those approaches suggested by S.1490 and other acid rain bills.

SO_2 EMISSIONS HAVE DECLINED SINCE ENACTMENT OF THE CLEAN AIR ACT

The fact is that SO_2 emissions have declined significantly since enactment of the original Clean Air Act and its amendments of 1977. Contrary to fact, acid deposition control legislation appears to be motivated, at least in part, by the perception that the current law is not working. The assumption is that industry does not share a concern for the environment and therefore, unless Congress legislatively mandates additional short term reductions in the level of SO_2 emissions, these emissions will again rise.

According to government estimates, almost $110 billion has been funneled into the U.S. sulfur dioxide control program since its inception. These expenditures have been made by basic industries, the utilities and the coal industry. The results attest to the success of the program. Federal ambient standards for SO_2 emissions are being met. As early as 1986, the Council on Environmental Quality stated that "It is clear that the SO_2 problem, from the standpoint of public health, has essentially been eliminated in the nation." [15]

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[15] Council on Environmental Quality, Environmental Quality, 15th Annual Report, 1986.

NAPAP's Interim Report, released in November 1987, found that over the 1973-1985 period total man-made emissions of SO_2 in the United States from all sources have decreased by 27 percent. The report went on to observe: "of particular note is that the trend has continued in recent years, 1980-85, when the total net reduction of national sulfur dioxide emissions from 1980 to 1985 is just over 10 percent." [16] Indeed, the U.S. Environmental Protection Agency's annual "National Air Quality and Emissions Trends Report, 1987" reinforces these findings and states that "the data clearly shows that over the long term the Clean Air Act has worked well in reducing pollution . . . ."

Since 1973, SO_2 emissions from utilities have declined from 19.0 million tons to 14.88 million tons or by 21.7%. During the same time that emissions were declining, utility coal consumption increased by 85 percent or by 329 million tons. In addition to supporting growth in electricity demand, coal has been used as a significant wedge against an increase in the use of imported energy. Use of coal has allowed utilities to cut use of petroleum, a more expensive and less reliable energy source, by more than 60 percent since peak consumption in 1978.

Between 1980, the year in which the 1977 Clean Air Act Amendments were just beginning to take effect, and 1987, emissions of sulfur dioxide at coal fired electric power plants in the United States declined by 1.3 million tons, or by 8.0 percent. The decline in the average emissions rate was even more significant, a fall from 2.68 lbs. SO_2/MMBTU in 1980 to 1.97 lbs. SO_2/MMBTU in 1987, or a 25.6 percent drop. If SO_2 emission rates had not declined during the seven year period, total SO_2 emissions from utilities would have been over 20 million tons in 1987 and not 14.8 million tons [17].

Industry analyses have found that the cause of the decline can be attributed to four distinct reasons: the result of the emission limit imposed on new plants that is more stringent than that for plants which were operating before the 1977 Clean Air Act requirements took effect; the movement of economic activity and electricity demand to regions which use lower sulfur coals and newer generation technology; substituting lower sulfur coals in power plants throughout the country; and, retrofitting new technology, in this case, scrubbers, onto plants not subject to the new source performance standards of the 1977 act.

The sharpest decline in emissions, 1.2 million tons between 1980 and 1987 occurred in the regions of most concern to the Canadians, the "border" regions from North Dakota east along the Canadian border to Maine. (This is 92 percent of the total national decline in emissions and is a full 50 percent of the two million ton reduction by 2000 from this region that has been requested by the Canadians.) This region, that has made the most progress in reducing emissions, the industrialized heartland of America, is the region most heavily affected by S.1490 and other acid rain proposals.

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[16] Interim Assessment. The Causes and Effects of Acidic Deposition, Volume I, Executive Summary, The National Acid Precipitation Assessment Program, 1987.

[17] "National Air Pollutant Emission Estimates, 1940 - 1987", EPA, March, 1989.

Proponents of acid rain legislation often cite forecasts which show an increase in SO_2 emissions as the underlying reason that more stringent controls on power plants are necessary. Based on the experience to date however, we believe that the constantly revised projections of rising SO_2 emissions must be discounted when making decisions regarding the need for additional legislated controls on sulfur emissions. [18]

Over the long term SO_2 emissions should continue to decline without additional legislative standards as older plants are retired and new and/or repowered units are brought on line. Finally, deployment of Clean Coal Technologies will contribute significantly to an accelerated reduction in SO_2 emissions and should be factored more heavily into future emission projections much as reflected in EPA's low base case forecast which shows a sharp reduction in emissions from power plants after 2005.

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[18] The EPA revised, biennial base case emissions forecast is one such forecast. The new edition of this forecast does corresponds more closely with NCA estimates than earlier forecasts, as the EPA estimates now (unlike past reports) incorporate the decline in emissions that occurred between 1980 and 1985 and recognize that, in the future, emissions levels will be affected by changes in state implementation plans and by limited repowering with clean coal technologies. Experience will prove that even these modified forecasts are still unrealistically high and overstate the emissions level that will be achieved, even in the absence of acid deposition control legislation.

For example, in 1995 the base case forecast shows that SO_2 emissions will be approximately 16.2 - 16.8 million tons from coal fired utilities, a forecast increase of 1.4 - 2 million tons higher than 1987 levels. This forecast is based on an approximate 780 - 810 million ton coal burn in 1995, and increase in consumption of 62 to 92 million tons above 1987 utility coal use. An increase in tons emitted of the magnitude forecast would require that each ton burned in 1995 in excess of the amount used in 1987 would have to emit at an approximate 2.00 lb.SO_2/MMBTU rate, somewhat higher than the average today. This is highly unlikely. Most new coal burn will occur at rates that are well below those that would be necessary to increase SO_2 emissions to the levels forecast.

NATIONAL COAL ASSOCIATION

ATTACHMENT A
TO ACCOMPANY STATEMENT OF

THE

NATIONAL COAL ASSOCIATION

HEARINGS ON
THE CLEAN AIR ACT AMENDMENTS OF 1989

before the
COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

JANUARY 24 - 25, 1990

EMISSION ESTIMATES FOR THE NON-UTILITY SECTOR

SO_2 Emissions
(000 short tons)

	1980	1985	1995	2000
Industrial Combustion	3,606	2,446	2,150	2,130
Other Combustion	1,153	580	510	450
Industrial Processes	3,473	2,907	2,642	2,627
Transportation	879	864	464	464
Other	365	39	39	39
	9,476	6,836	5,805	5,711

Note: 1980 and 1985 emissions are from NAPAP inventories.

The forecasts of energy consumption by sector used in this analysis are from the Energy Information Administration's latest long-range forecast.

INDUSTRIAL COMBUSTION
OTHER COMBUSTION

Industrial combustion emissions should decline between 1985 and 2000 for several reasons: (1) the new NSPS standards for industrial boilers will require any new fuel sources to achieve 90% removal (2) gas and oil prices are now forecast to be lower relative to coal prices, leading to the use of more gas and oil and less coal (3) while oil is forecast to increase as an industrial fuel, use of residual fuel oil, which is the high sulfur oil, is now forecast to decline steadily (4) the forecast for non-utility generation sales to utilities has more than doubled over the forecast of three years ago, and most of the new generation is expected to be from new IPPs which must meet NSPS requirements and (5) all of the increase in industrial coal use is all in the non-utility generation sector, and there will be a decline in the traditional markets for industrial coal.

Industrial coal use in traditional markets will fall from 70 million tons in 1985 to 65 million tons in 2000 according to EIA's forecast. NUG coal consumption will increase to 18 million tons. Combining the drop in traditional coal consumption with a slight continuation of the trend of improving emissions per ton of coal burned, and adding emissions from the NUG sources at NSPS rates leads to the forecast improvement in emissions. The impact of the decline in residual oil emissions is also included, although this is a much smaller factor. (This forecast for emissions from industrial boilers does not include any attempt at estimating the effects of the President's bill.)

Other combustion sources includes both commercial and residential fuel consumption. Coal use in the residential/commercial sector is forecast to decline from 8 million tons in 1985 to 7 million tons in 1995 and 6 million tons in 2000. Both the overall consumption of oil and the consumption of residual fuel oil are forecast to decline through the year 2000, as gas and most notably, electricity become the major fuels in this sector. The forecast is simply an estimate of the effect of these trends.

INDUSTRIAL PROCESSES

Four of the largest sources of industrial process emissions are copper smelting, petroleum refineries, cement production and iron and steel production. Emissions for these four categories were forecast separately, and emissions from the combination of all the smaller, remaining categories were assumed to remain at the 1985 level overall.

SO_2 Emissions
(000 short tons)

	1980	1985	1995	2000
Industrial Processes:				
Copper Smelting	1,099	637	400	400
Petroleum Refineries	623	488	488	488
Cement Production	346	113	95	85
Iron and Steel	193	145	135	130
Other	1,212	1,524	1,524	1,524
TOTAL	3,473	2,907	2,642	2,627

Note: 1980 and 1985 emissions are from NAPAP inventory.

Copper smelting is the largest component of industrial processes emissions. The copper industries continues the modernization and rationalization process because of the high environmental and energy costs. Several smelters closed because it was too expensive to comply with environmental regulations. In 1980 there were 16 smelters with production capacity of 1.9 million metric tons. In 1985 there were 11 smelters with production capacity of 1.4 million metric tons, and in 1987 there were 9 smelters with 1.2 million metric tons of capacity.

The type of capacity has also been changing. In 1980 there was 958,000 metric tons of reverberetory furnace capacity, compared with 386,000 metric tons in 1987. These furnaces have closed or replaced by flash smelters. Reverberetory furnaces produce a weak concentration of sulfuric acid which is difficult to capture with sulfuric acid plants whereas flash furnaces produce a stream with a higher concentration of sulfuric acid. The flash furnace technology can control 99+ percent of potential emissions. Since 1987 one more reverberetory furnace has been retrofitted with a flash furnace.

According to DOC's 1989 U.S. Industrial Outlook, several copper producers are investing in solvent extraction-electrowinning (SX-EW) plants which is a technology that produces copper by leaching the metal from low-grade copper waste or oxide ore. The capital costs of SX-EW are roughly one-half those of the conventional copper smelting process while environmental costs are extremely low. It is expected that this process will increase its share of production.

Copper consumption is expected to continue its slow rate of increase. The combination of low growth in consumption, inroads by the SX-EW process and improved environmental performance of the smelter industry should lead to a decline in emissions from copper smelting.

Petroleum refineries have decreased their emissions between 1980 and 1985. The EIA forecast predicts fairly slow growth in demand for refined petroleum products and an increase in imports of refined petroleum products. OPEC countries have been pursuing downstream integration which would account for the forecast of increased imports.

(million barrels per day)	1980	1985	1987	2000
Imports of Refined Petroleum Products	1.65	1.87	2.00	2.54
Refined Petroleum Products Supplied	17.06	15.72	16.67	18.61

Source: Energy Information Administration, Annual Energy Outlook, 1989.

EIA's forecasts of imports for 1988 and 1989 are much lower than the actual experience, while its forecasts for supply are right on target, indicating that the potential growth in imports may be underestimated. Refined petroleum products are being imported at an average of 2.37 million barrels per day through May of 1989. (Monthly Energy Review estimate.) The rise in imported refinery products could result in even slower growth in domestic refinery products.

The domestic refining industry has had to adjust to changes in type of product demanded, and to new environmental restrictions; these factors are expected to continue to affect the operations of the refining industry. The combination of slow growth in demand for refined petroleum products, increasing imports and a continuation of the improvement seen in emission rates leads to the forecast of no growth in emissions in the petroleum refining sector.

Cement production has grown very slowly throughout the 1980s, while imports have increased dramatically. Cement demand and imports are both projected to continue to grow, although imports will not grow as fast as demand (DOC). U.S. producers continue to shut down less efficient plants because of competition from low-cost imports and the current world overcapacity of cement. New technological developments are concentrated on energy efficiency. Coal consumption by the cement industry has been declining slowly since 1985 even though cement production has increased. EIA's forecast does not go into detail about the industrial sector, but NCA's forecast predicts a continuation in the decline in coal consumption by about 2 million tons between 1987 and 2000. Thus a small decline in emissions is likely.

Industrial processes includes coal consumption in coking ovens. Metallurgical coal consumption declined from 67 million tons in 1980 to 41 million tons in 1985. The trend is expected to continue, with coal consumption falling to 37 million tons in 1995 and 36 million tons in 2000.

TRANSPORTATION

The forecast of emissions reduction in the transportation sector is based on the proposed reduction to .05 of sulfur in diesel fuel. This reduction is included in the President's bill, and also is being proposed by EPA for enactment by 1993.

BACKGROUND FOR DATA INCLUDED IN
STATEMENT OF

THE

NATIONAL COAL ASSOCIATION

HEARINGS ON
THE CLEAN AIR ACT AMENDMENTS OF 1989

before the
COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

JANUARY 24 - 25, 1990

TO ACCOMPANY CHART 3

RELATIVE CONVERSION EFFICIENCIES FROM COAL-FIRED FACILITIES

Technology	Fuel	Conversion Efficiency (approx.)	% Change In Conversion Efficiency[1]
Conventional Pulverized Coal (w/FGD)	Coal	30-33%	--
Conventional Combustion w/Advanced Flue Gas Cleaning	Coal	35%	+6.1%
Conventional Pulverized Coal (w/o FGD)	Coal	36%	+9.1%
Advanced Cleaning	Coal	36%	+9.1%
Atmospheric Fluidized Bed Combustion	Coal	36%	+9.1%
Pressurized Fluidized Bed Combustion	Coal	40%	+21.2%
Integrated Gasification Combined Cycle (IGCC)	Coal	42%	+27.3%
IGCC w/Fuel Cell	Coal	50%	+51.5%
MHD	Coal	55%	+66.7%

[1] Using Conventional Pulverized Coal with FGD as a base, 33% efficiency.

Assumptions: 2.8% sulfur coal, 11,600 BTU/lb
65% Capacity Factor
Nominal 500 MWe Electric Power Plant
90% sulfur removal (where required)

TO ACCOMPANY CHART 4

Range of Estimated Commercial Availability Dates of Clean Coal Technologies

(assume implementation of a clean coal deployment program)

Technology Class	available for Commercial Order[1] (Range of Estimates)	Potential Widespread Commercial Use to Achieve Reductions of Air Pollutants[2]
Advanced Physical Coal Cleaning	1994-1996	2000-2005
Chemical Coal Cleaning	1998-2000	2010-2015
Low Grade Coal Upgrading	1993-1995	1990's-2000
Advanced and Regenerable FGD	1995-1998	2005-2010
Furnace Sorbent Injection	1993-1995	2000-2005
Duct Sorbent Injection	1994-1996	2000-2005
NO_x Control During Combustion	1996-1998	2005-2010
NO_x Control Post Combustion	1996-1998	2005-2010
Integrated Gasification Combined Cycle	1996-1998[3]	2005-2010
Utility-Scale Atmospheric Fluidized Bed	1994-1996[3]	2000-2005
Pressurized Fluidized Bed	1998-2000	2005-2010

1. These dates assume that the ongoing clean coal technology demonstration program continues; that a deployment program providing for several subsequent commercial-scale demonstrations of the same or similar technology will be fully implemented (number of deployment projects will vary by technology); that neither the demonstration nor deployment projects will fail; and, that deployment projects of the same generic technology will be initiated roughly in parallel and not in sequence to accelerate further the development schedule, (though the sequential approach would save dollars and permit maximum learning value from the prior projects). A successful deployment program is intended to provide sufficient operating experience with a given technology to establish technical feasibility, economic competitiveness with other commercially-available options, and qualified suppliers capable of guaranteeing the technology's performance.

2. These dates assume that industry will not be precluded from using the technology once it has been successfully demonstrated and deployed. To make a significant contribution to the reduction of atmospheric pollutants, the clean coal technologies must penetrate the market. Depending upon the degree of difficulty, size and complexity of each clean coal project or application, each commercial clean coal project will require 2 to 3 years from start date to placed-in-service date for simple engineering modifications and 5 to 7 years for projects requiring major equipment installation. Initially, to minimize risk, a utility will apply a retrofit or repowering technology to one or two units and not to the entire system. Once that utility gains experience and confidence in the technology it will likely be applied to other units in that utility's system. Each utility is likely to proceed in this same manner depending upon its individual, and unique, circumstances. Further, utilities will not all proceed to use such technologies at the same time. Therefore, significant market penetration which, in turn, will likely yield a significant contribution to the reduction of air pollutants, will take time and a decade beyond the date of commercial readiness is not an unreasonable estimate. Forcing use of the technologies through requirements for

early reductions will only lead to abandonment of the newer technologies in favor of currently available technology, for example, wet-limestone scrubbers.

3. Several equipment suppliers and manufacturers are currently prepared to offer, with performance guarantees, gasification units or atmospheric fluidized bed boiler units. However, these units, while large enough for some utility applications, are generally considered to be too small for widespread utility use and/or do not demonstrate the integration of multiple equipment trains. The estimated availability dates cited in the chart assume that the technology will have been demonstrated and deployed, by those dates, at a size large enough (greater than 400 megawatts) to be suitable for widespread utility-scale use.

WRITTEN TESTIMONY OF
PG&E-BECHTEL GENERATING COMPANY

TO THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

JANUARY 24, 1990

I. INTRODUCTION

PG&E-Bechtel Generating Company ("PG&E-Bechtel") appreciates the opportunity to submit comments to the Senate Energy and Natural Resources Committee on the energy policy implications of S.1630, the "Clean Air Act Amendments of 1989".

PG&E-Bechtel is a joint venture comprised of one of the nation's largest power systems and the largest international power plant engineer and constructor. Our business objectives are to develop, finance, construct and operate the next generation of environmentally clean and energy efficient power plants.

Independent power producers ("IPP's") such as PG&E-Bechtel have been responsible over the past ten years for approximately 50% of the additions to generating capacity in the United States. Over the next 20 years the U.S. utility industry will need to replace over 50,000 MW of aging powerplants with new generation sources. New plants built by the IPP industry will represent a significant amount of these new additions of capacity and are critical to maintaining adequate supplies of electricity through the beginning of the next century.

Much of this next generation of new powerplants is presently under construction, receiving permits, or will begin to be planned for during the next 3-5 years. The renewal process is underway and represents a considerable amount of capital investment and planning effort.

While we generally support S.1630, unless the bill is modified, it may have the effect of inhibiting the IPP industry from continuing to supply reliable clean electricity in the 1990's and beyond.

We believe that a few minor changes to S.1630 will resolve major problems currently overlooked: the treatment of projects which are under various stages of development today and the treatment of IPP projects planned for operation over the next 5-10 years.

II. Need to Redefine "Existing Units"

The Senate bill divides existing power plants into seven separate categories and limits the sulfur dioxide emissions that will be allowed from each starting in the year 2000. A power plant is "existing" if it commences operating before the acid rain bill is enacted.

The bill puts in a bind any IPP project for which a long-term contract to supply electricity to a utility has been signed, but whose power plant will not start operating until after the acid rain bill is enacted. This power plant is a "new" unit. The independent producer must buy SO_2 allowances to operate after

1999. Under the signed contract, the price at which he committed to supply electricity has been fixed by the long-term contract and does not take into account this new, additional expense. While a utility could simply pass through this additional cost to its ratepayers, an independent producer cannot.

An example of such a project is the DuPont, Chambers Cogeneration Project in New Jersey. In this project, DuPont and PG&E-Bechtel plan to build a 224 MW, coal-fired cogeneration plant at DuPont Chambers Works petrochemical complex in Deepwater, New Jersey. Construction on the $500 million power plant is scheduled to begin in mid-1990, with initial operation scheduled for 1993. The plant will provide steam and about 40 MW of electricity to DuPont for internal use, plus 184 MW for sale to Atlantic Electric Company.

The Project will produce this power at an emission rate of .22 lbs/MMBtu. This is almost a full lb/MMBtu below the 1.2 lbs/MMBTu future standard as proposed in S.1630. An equivalent existing plant will be allowed to produce over 12,000 tons/year of SO_2 more than the Chambers Project.

The Power Sale Agreement with Atlantic Electric Company was signed in September 1988. As of that date, the revenue that PG&E-Bechtel will receive for the sale of the electricity from the Chambers Works Project was fixed. S.1630's requirement for the purchase of SO_2 offsets, assuming they are available at all, is an additional expense item of unknown magnitude.

The addition of this new expense imperils the economic viability of projects in this situation. More importantly, however, the uncertainty of this availability of offsets will prevent the financing of these projects.

Given the importance of new projects, such as Chambers Works, to continued reliable electric supply, such projects at an advanced development stage should be treated as "existing" units and either given allowances based on their expected emissions or permitted to operate without allowances under some form of SO_2 limitation consistent with the state air permit. Such relief should be given to any IPP project for which signed contracts to supply electricity on a date certain exists. The date for such an exemption should be the date that the President's acid rain bill was first introduced last year in the House.

III. Penalizes Greater Efficiencies of IPP's

A second problem with respect to S.1630 and IPP's relates to the fact that existing power plants that commenced operating after 1984 fall under section 405(g) of the bill. The emissions limit for a power plant in this category is a tonnage limit based on the rate specified in the air permit for the facility and the assumption that it operates only at 65% capacity. This provision is apparently no burden for utilities, but it penalizes independent producers whose facilities must operate at 85% to 90% capacity in order to pay debt service. The greater efficiency of independent producers should not be penalized.

Another problem with S.1630 is a technical restriction aimed at preventing any industrial company that elects to bring its existing boiler under the new SO_2 limits and receive allowances from abusing the privilege. Section 410(f) of the bill would prevent the company from selling an allowance that it no longer needs because of "reduced utilization or shutdown" of the boiler.

An independent producer may enter into an arrangement with a paper mill, for example, where the mill shuts down its dirty boiler and agrees to buy steam from a cleaner facility that the independent producer plans to build. The independent producer produces steam as an intermediate step toward generating electricity, so it has steam to sell. In this case, the independent producer ought to be able to purchase any unused allowance from the paper mill.

IV. New Projects - Ensuring A Viable IPP Industry During Transition Period

The Senate bill would set aside 2% of allowances in a reserve for the EPA to sell to owners and operators of new units. The bill would give EPA three years after the bill is enacted before it must issue regulations to implement the reserve. Meanwhile, any bank lending money to finance construction of a new power plant will want an assurance that allowances can be obtained to operate the facility. The result would be a halt for several years in construction of new power plants by independent producers. Utilities would not face the same problem since they typically have either the ability to create their own offsets or the ability to repay loans from their total revenues notwithstanding whether a project operates or not.

A special emissions allowance bank should be created which guarantees the availability of allowances by statute. EPA should be required to begin maintaining a reservations list within six months after the bill is enacted for projects needing assurances that such allowances are available. The list would be filled on a first come-first served basis.

A person would have to satisfy three tests before being put on the list. First, the project must be "super clean," meaning SO_2 emissions of 0.3 lbs/MMBtu or less. Second, he must have an air permit to construct, a construction contract, and a contract to sell electricity to a utility. Third, he must make some downpayment to EPA or into an escrow account within two years after being put on the list. The last two requirements discourage mere placeholders and ensure that a person cannot apply to EPA to be put on the list until close to the time when he needs to demonstrate to a bank lender that allowances can be obtained.

Two alternative solutions are also available to accomplish the same result as guaranteeing access to the reserve pool. The first would be to mandate that, for IPP's, SO_2 offsets are the obligation of the utility purchasing the power. They could either provide the offsets from their own system or purchase them from the EPA reserve.

Indeed, we are uncertain whether the 2% reserve would be sufficient to ensure a competitive independent producer segment. Consideration should be given to expanding these reserves to 5%, which would ensure a sufficient pool of SO_2 allowances.

V. Conclusion

The problems caused by S.1630 for the independent power industry are very real. They dramatically and inequitably impact on both on-going projects and new projects and, as a result, threaten the viability of reliable electric supply over the next few years. PG&E-Bechtel was formed to provide safe, clean and economical new sources of electric power. Our concerns, as well as those of the rest of the industry, can be addressed without doing violence to either the structure or the goals of the Clean Air Act Amendments.

With these amendments to the final bill, we could support this important environmental legislation.

NSP

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Telephone (202) 639-4051

Gay H. Friedmann
Director Federal Governmental Affairs

February 20, 1990

The Honorable J. Bennett Johnston
Chairman
Senate Energy and Natural Resources Committee
364 Dirksen Senate Office Building
Washington, D.C. 20510
ATTENTION: Patty Beneke

Dear Mr. Chairman:

Enclosed is testimony submitted on behalf of Northern States Power Company (NSP). I would appreciate it being included in the record.

If you have any questions or I can be of further assistance, please don't hesitate to call.

NSP looks forward to working with you and the other Members of the Committee. Thank you for your assistance.

Sincerely,

Gay H. Friedmann

NORTHERN STATES POWER COMPANY
COMMENTS ON ACID RAIN AND AIR TOXICS LEGISLATION

Mr. Chairman, Members of the Committee, this testimony is submitted to discuss Northern States Power Company's views on the critical issue of acid rain and air toxics legislation. We are pleased that it appears as if Congress finally will pass legislation to mitigate acid rain causing emissions as the state of Minnesota has already done.

I. Background

Northern States Power Company (NSP) is an electric and gas utility serving approximately 1.5 million customers in Minnesota, Wisconsin, North and South Dakota and Michigan's upper peninsula. NSP has long recognized that our public service obligation consists of more than simply providing least cost, reliable energy. We believe, as do the citizens of Minnesota, that we must also respect our nation's environment. We view acid rain as an environmental problem with potentially far reaching consequences. Thus, we continue to consider these issues when we plan our power supply and to evaluate the potential impact our decisions will have on the environment.

This is the spirit in which we are submitting testimony today. NSP wholeheartedly supports the passage of comprehensive acid rain legislation designed to maintain the integrity of our nation's lakes and rivers, forests and farmland, and scenic beauty. We believe these goals can and should be met without placing an unfair burden on our customers or shareholders.

II. The NSP System

NSP has invested more than $600 million in pollution control over the last 20 years, $350 million of it to mitigate acid rain causing emissions. Additionally, we burn low sulfur coal. Our coal fired system average S02 emission rate is .54 lbs/MBtu, far below the 1.2 lbs/MBtu standard proposed by the most stringent acid rain legislation pending before Congress. From 1970 through 1988, NSP decreased its S02 emissions by 74 percent while increasing fossil-fired generation by 51 percent.

This record has earned NSP accolades from the Friends of the Earth Foundation and the New Hampshire Citizens Task Force on Acid Rain in the form of awards for making outstanding contributions toward solving the acid rain problem. NSP is justifiably proud of its environmental record.

Sherco 1 & 2

Our first two Sherburne County (Sherco) units came on line in 1976 and 1977. Each can produce 710 megawatts of electricity. These two units were on line 90 percent of the time from 1985 through 1987, with an average capacity factor of 65 percent. Sherco 1 & 2 utilize wet scrubbers to neutralize and trap SO2 created in the burning process. The scrubbers for these units cost NSP's customers approximately $35 million to install. In addition, the two units burn 100 percent Western low-sulfur coal. Their 1988 emission rate was .35 lbs/MBtu.

Sherco 3

Sherco 3, the largest and newest unit in our system which produces [illegible] megawatts of electricity began commercial operation in November, 1987, and recorded an outstanding 1988 on-line performance of 93 percent, with a capacity factor of 71 percent. Nearly 30 percent of this plant's construction cost of $1.1 billion is invested in pollution control equipment. Its dry scrubbing system and bag house filters, which remove SO2 and particulates, cost our customers $230 million. Sherco 3 also burns low-sulfur Western coal. Its 1988 emission rate was .36 lbs/MBtu. We are exceedingly concerned about how emission limits would be calculated for Sherco 3 under the Administration bill, since it did not operate during the Administration proposed 1985-1987 baseline years.

Riverside

Riverside 7, a 140-megawatt unit equipped with a dry scrubber and a bag house, is a 1981 retrofit project and was the first operating utility-scale demonstration of this technology. The cost to NSP customers was $8.2 million. Riverside 7's 1988 emission rate was .60 lbs/MBtu.

Black Dog

NSP has successfully applied one of the first clean coal technologies in the United States at its Black Dog generating plant. NSP converted a boiler to a fluidized bed combustor, a technology which improves the efficiency rate of combustion and uses limestone to trap SO2 without additional scrubbing. This 130 megawatt unit has one of the first utility sized fluidized beds in the country. The investment, made in 1985, cost our customers more than $30 million.

III. The Current Debate

We are pleased that this committee is debating the acid rain and air toxics legislation currently pending before the Senate. You know the divisiveness of the issues that must be resolved. We will focus our remarks on a few of these issues.

We will address some of the potential energy implications of the acid rain bill. We will also address five major issues of which we have concern or interest in the pending legislation. These are:

1. Allowances: The allowance system in the acid rain proposal penalizes companies like NSP who have been reducing SO2 emissions over a long period of time by providing few allowances. The majority of the allowances will be rewarded to those utilities who have "dragged their feet" the longest. More flexibility is needed for clean units.

2. Cost-Sharing: The allowance system is a form of cost-sharing. NSP cannot support yet another form of cost-sharing such as an emission-fee or generation tax.

3. NOX Standards: NSP opposes the NOX provisions in the Senate bill that would cap existing units at their '85-87 baseline and preclude these units from increasing their generation. The NOX emission standard set in the bill is also too restrictive. Although a NOX cap is not practible, we can support feasible low NOX burner emission rates.

4. Air Toxics: There currently is insufficient information on the effects of air toxic emissions from electric utilities to warrant the proposed regulations and resultant cost to utility customers. NSP supports having a study of the impact of these emissions by EPA which looks at health effects and recommends reasonable technology, if controls are deemed necessary.

5. Clean Coal Technology: NSP supports continued development of and incentives for clean coal technology.

A. ENERGY IMPLICATIONS

NSP believes that pending acid rain legislation has the potential to dramatically limit the use of coal-fired power to meet this nation's energy supply requirements. Yet coal is currently our nation's most abundant energy resource and is used to generate nearly 60 percent of our nation's electricity. Currently, the future of nuclear power remains uncertain due to problems associated with licensing and high and low level waste disposal. As a nation, we have not yet committed the resources necessary to fully develop renewable sources of energy that are economically viable.

As a result, this nation is faced with the option of relying on natural gas for a growing proportion of our electricity requirements. While natural gas can be part of the solution, reliance on only one fuel is fool-hardy. Although natural gas has been a relatively stable source over the past few years, we could again see price volatility and dwindling reserves. We should also see more imports of this fuel from Canada. The backup fuel for natural gas is oil. Our oil imports were 46% in 1989 as released by the American Petroleum Institute recently. Northern States Power questions the wisdom of a policy which encourages overreliance on any one fuel to meet this nation's critical energy requirements. We believe all supply and demand options must be on the table and be able to play a role to ensure a prosperous economy.

B. THE ALLOWANCE SYSTEM, EMISSIONS TRADING AND OFFSETS FOR NEW GROWTH

NSP has long supported federal action to reduce acid rain causing emissions at the lowest possible cost. Recently, various market oriented trading schemes have been proposed which would allow utility systems to purchase rights to emit SO2 and oxides of nitrogen from other utilities or industries as part of the plan to reduce SO2 and NOX.

The trading scheme receiving the most attention from the Congress is contained in H.R. 3030, H.R. 1490 and S. 1630 which is pending before the Senate. We are extremely concerned with this trading scheme for several reasons.

First, utilities with low system-wide emission rates, such as NSP, might not be able to generate sufficient offsets internally to add new capacity. To do so, we must reduce our exceedingly low current emission rate even further, and this certainly could not be done efficiently or cost-effectively. This means that a company with low system-wide emission rates would have to purchase offsets in the marketplace at potentially prohibitive costs. Many of the utilities with the greatest number of offsets will be those companies that have dragged their feet longest in reducing SO2 emissions. This penalizes utilities that have led the nation in reducing SO2. Conversely -- and perversely -- this scheme rewards the recalcitrant systems by providing them with a potentially valuable asset, and thus could encourage delay in achieving environmental clean-up goals. A company like NSP, with a coal-fired system-wide SO2 emissions rate of .54 lbs/MBtu, would be forced to purchase offsets from systems with current emission rates of 3 lbs/MBtu or higher. This proposal clearly sends the wrong signal to utilities/companies that have led the way in protecting the environment: Delay cleaning up and you will be rewarded, it says.

Another potential problem: This trading scheme assumes that companies holding the offsets will be willing to sell them. This is in no way clear. Utility industry witnesses have testified before the House Energy and Commerce Committee that they would not be inclined to sell their offsets. Commissioner Badger also testified before your Committee stating that PUCs would be reluctant to permit trading outside a utility's service area or regional power pool. If trading does not occur, offsets sufficient to add new coal-fired generating capacity might be unavailable in some regions of the country, raising serious implications for the nation.

NSP supports an amendment that would give additional allowances to clean utilities to provide needed flexibility to run their systems and equitable treatment in the trading system. This "Class of 85" amendment is attached.

C. COST-SHARING

As it is currently structured, the allowance trading system itself amounts to a form of cost-sharing which discriminates against those utilities, including NSP, which made significant investments in emissions reductions prior to the system's baseline year. As a system with a very low emission rate, NSP would receive fewer allowances under the proposed legislation. As mentioned above, we would be faced with further reducing our emission rates (not efficient or cost effective), taking a plant off line to build a new plant or purchasing allowances from other systems which have not made a comparable investment in pollution reduction. This is an inequity to our customers, who have already shouldered the burden of reducing acid-rain causing emissions in our service territory. The current allowance trading system, like more traditional cost-sharing schemes, may require our customers to pay twice for cleaner air simply because their utility and state government responded to the problem first. The inclusion of an emissions fee or generation tax would force our customers to pay yet a third time for cleaner air.

D. NOX EMISSIONS AND CAP

The proposed Senate legislation places a cap on existing utility NOX emissions from tangentially - and wall-fired pulverized coal boilers. The cap is based upon stringent low NOX burner emission rates multiplied by the unit's average fuel consumption from years 1985-1987. Even after the installation of low-NOX burners, this proposal would require NSP to be held to its average capacity factor of 1985-1987. If we increase our generation above this level, which NSP must do to meet increasing demand, we will have to obtain sufficient allowances. If these allowances are not available, we will be forced to install selective catalytic reduction (SCR) technology. NSP estimates the capital cost of SCR technology on our system will approach $500 million. NSP is also concerned because SCR is not a proven utility-scale technology. Use of SCR could impact system reliability and would increase plant operating costs and station electrical use.

NSP cannot support a NOX cap. However, we will support feasible low NOX burner technology emission rates. This would apply state-of-the-art technology to NOX emissions while allowing for required system growth.

E. AIR TOXICS

With respect to air toxics; NSP conducts elemental analysis on the coal we burn and, consequently, has rough emission estimates for trace metals. However, actual stack emissions are not known. We will begin stack testing at Sherco in early 1990 in an attempt to obtain specific information regarding these emissions. These tests will be made in conjunction with our existing monitoring programs that we have been conducting in the vicinity of Sherco for the past 15 years. Information from this monitoring and other research, including EPA reports, show that these utility emissions are not a threat to human health or the environment.

The current Senate proposal will require electric utilities that emit over 10 tons of one chemical per year (on a list of over 190 chemicals) or 25 tons in aggregate at a facility to install Maximum Available Control Technology. We believe this would require NSP to install scrubbers and bag houses at all of our major facilities. We estimate the cost of the Senate provisions to NSP customers is $580 million. We request that the legislation be amended to contain a provision for study of utilities' air toxic emissions and their associated health impacts similar to that proposed by the Administration. This would ensure that both impacts and benefits are prudently assessed before costly control technologies are mandated.

F. CLEAN COAL TECHNOLOGIES

Clean coal technologies allow use of the nation's vast coal reserves while minimizing impact on the environment. NSP believes clean coal technologies are a viable way to lower emissions that contribute to acid deposition, improve efficiency and minimize global warming impacts and costs. The provisions in the Clean Air

Act amendments that allow for the further development of these technologies will allow utilities more options which will encourage rather than frustrate emission reductions.

Some clean coal technologies are commercially available today. NSP has been developing a clean coal technology since 1980 in pursuit of its commitment to reducing emissions. Our French Island plant was converted in 1981 to an atmospheric fluidized bed combustor (AFBC). It was the first full-scale commercial AFBC in the United States. This work was in preparation for the 130 megawatt AFBC conversion at the Black Dog plant in 1985.

NSP believes it has unique experience and practical expertise in fluidized bed boilers. A subsidiary, NRG, was formed to market that experience. Fluidized-bed combustion is a commercially available clean coal technology that results in reduced SO2 and NOX emissions while maintaining an adequate, reliable supply of electricity.

IV. CONCLUSION

We appreciate the opportunity to present NSP's concerns regarding the acid rain and air toxics provisions pending before the Senate as part of the Clean Air Act. We would like to continue working the Members of this Committee to resolve the problems associated with the legislation pending before the Senate.

A Proposal By the Class of '85 To Amend § 405 of S. 1630

Section 405(c) of S. 1630 is hereby amended by striking subsection (c) and inserting in lieu thereof the following:

> "(c) Coal or Oil-fired Units Below 75 MWe and Above 1.2 lbs/mmBtu. -- After January 1, 2000, it shall be unlawful for any coal or oil-fired steam-electric existing unit with nameplate capacity less than 75 MWe and actual 1985 emission rate equal to or greater than 1.2 lbs/mmBtu to exceed an annual sulfur dioxide tonnage emission limitation equal to the product of the unit's baseline multiplied by the lower of its actual 1985 emission rate or 2.0 lbs/mmBtu.

Section 405(d) also is amended by striking everything after the words "equal to" on line 8 and inserting in the lieu thereof:

"one of the following:

> 1) the product of the unit's baseline multiplied by a factor of 120 per centum and its actual 1985 emission rate, divided by 2000; or
>
> 2) the unit's actual baseline multiplied by the lower of 1.0 lbs/mmBtu or the federally approved emissions rate, divided by 2000;

> unless the owner or operator of such unit has obtained allowances equal to the emissions in excess of those permitted under this subsection. Each utility must declare by December 31, 1999, which option it is selecting for application to its coal units and the selected option shall be applicable to all units owned by the utility within a state.

Finally, subsection 405(h) is amended by striking subsection in its entirety and inserting in lieu thereof following:

> "(h) Oil and Gas-fired Units Less Than 0.4 lbs/mmBtu and Less Than 10% Oil. -- After January 1, 2000, it shall be unlawful for any oil and gas-fired unit with an actual 1985 emission rate of less than 0.4 lbs/mmBtu and consumes annually, on a Btu basis, more than 90 per centum of its fuel in the form of natural gas, to exceed on an annual basis an emission rate of 0.4 lbs/mmBtu or its federally approved emission limitation, whichever is lower. Upon retirement of an existing unit under this subparagraph, the utility owning such unit will receive allowances equal to the number of allowances the unit would have received based on the product of the unit's 1985 emission rate times the baseline, divided by 2000.